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Central Heating and Power Plant Conversion at Fort Wainwright, AK

Heating Only with Backup Generation Option

John L. Vavrin, Noel L. Potts, John Westerman, Robert Lorand, Charles Schmidt, Raymond Heintel, and Michael R. Kemme

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Final Report

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ABSTRACT: The Fort Wainwright (FWA) military community has a critical need to establish its power and heating requirements to successfully complete a series of planned capital improvements. The CHPP upgrade coincides with an expansion of FWA's mission within the next 5 years. To help the installation successfully complete these changes within the specified time frame, the Construction Engineering Research Laboratory (CERL) conducted an independent technical assessment of the FWA CHPP. This follow-on study, which was completed in April 2003, expanded on the recommendation of previous work to convert the installation CHPP to heating only, and to purchase all electricity from the local electric utility.

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Conversion Factors

Non-SI* units of measurement used in this report can be converted to SI units as follows:

Multiply	By	To Obtain
acres	4,046.873	square meters
cubic feet	0.02831685	cubic meters
cubic inches	0.00001638706	cubic meters
degrees (angle)	0.01745329	radians
degrees Fahrenheit	(5/9) x (°F – 32)	degrees Celsius
degrees Fahrenheit	(5/9) x (°F – 32) + 273.15.	kelvins
feet	0.3048	meters
gallons (U.S. liquid)	0.003785412	cubic meters
horsepower (550 ft-lb force per second)	745.6999	watts
inches	0.0254	meters
kips per square foot	47.88026	kilopascals
kips per square inch	6.894757	megapascals
miles (U.S. statute)	1.609347	kilometers
pounds (force)	4.448222	newtons
pounds (force) per square inch	0.006894757	megapascals
pounds (mass)	0.4535924	kilograms
square feet	0.09290304	square meters
square miles	2,589,998	square meters
tons (force)	8,896.443	newtons
tons (2,000 pounds, mass)	907.1847	kilograms
yards	0.9144	meters

**Système International d'Unités* ("International System of Measurement"), commonly known as the "metric system."

Preface

This study was conducted for Assistant Chief of Staff for Installation Management under Military Interdepartmental Purchase Request (MIPR) 2JCERG4065, "Assessment of Required Power and Heat for Fort Wainwright Military Command, Alternatives to Current System and Recommendations for Future Work"; Work Unit CFM; Task GB22. The technical monitor was Hank Gignilliat, DAIM-FDF-U.

The work was performed by the Energy Branch (CF-E) of the Facilities Division (CF), Construction Engineering Research Laboratory (CERL), and concluded in April 2003. The CERL Principal Investigator was John L. Vavrin. Part of this work was done by Schmidt Associates, Inc, Cleveland, OH and Science Applications International Corporation, German-town, MD under contract No. DACA88-98-D-0003, delivery order No. 0013. The technical editor was William J. Wolfe, Information Technology Laboratory. Thomas Hartranft is Chief, CEERD-CF-E, and Michael Golish is Chief, CEERD-CF. The associated Technical Director was Gary W. Schanche, CEERD-CV-T. The Director of CERL is Dr. Alan W. Moore.

CERL is an element of the U.S. Army Engineer Research and Development Center (ERDC), U.S. Army Corps of Engineers. The Commander and Executive Director of ERDC is COL James R. Rowan, and the Director of ERDC is Dr. James R. Houston.

1 Introduction

Background

The Fort Wainwright (FWA) military community has a critical need to establish its power and heating requirements to successfully complete a series of planned capital improvements. By 2005, the Central Heating and Power Plant (CHPP) will have had over $90 million worth of planned capital improvements. If unforeseen deficiencies are found, it is estimated that his figure may rise even higher. At the time of this work, the boiler and systems upgrade, originally estimated to cost $29 million, had increased to $45 million. The baghouse project, originally awarded for $25 million, was also anticipated to require additional funds. The cooling system upgrade, a congressional add-on that was to have been awarded in September 2002, was estimated at $23 million. FWA had requested an additional $60M to correct all deficiencies and for other anticipated projects. However, according to plant personnel, only about $25 million was needed to complete the current OMA project and to keep the plant operation for 10+ years.

The CHPP upgrade coincided with FWA's expanding mission. Within 5 years of this project, FWA was scheduled to receive the Stryker Brigade Combat Team (SBCT), a new high-tech training simulator, and a new hospital, all to come on-line. To help the installation successfully complete these changes within the specified time frame, the Office of the Assistant Chief of Staff for Installation Management (ACSIM) requested the U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory (ERDC-CERL) to conduct an independent technical assessment of the FWA CHPP. This study, which was completed in April 2003, was undertaken to expand on the recommendation of the earlier work* to convert the installation CHPP to heating only, and to purchase all electricity from the local electric utility.

* Martin J. Savoie, John L. Vavrin, Michael R. Kemme, Charles Schmidt, John Westerman, John Lanzarone, Hank Gignilliat, and Norm Miller, *Central Heating and Power Plant Alternatives Review: Fort Wainwright, Alaska*, ERDC/CERL TR-03-11 (Engineer Research and Development Center, Construction Engineering Research Laboratory [ERDC- CERL], Champaign, IL, May 2003).

Objective

The overall objective of this project was to assess the condition of the Fort Wainwright Central Heat and Power Plant, analyze alternatives to the current system, develop recommendations for future project work, and provide feedback to senior Army leadership. This work was to more fully exploring the previous study's recommendations, which were to:

1. Convert the CHPP to heating only
2. Purchase all electricity from the local electric utility, Golden Valley Electric Association
3. Install backup generation on the Installation.

Approach

The assessment team contracted assistance from Science Applications International Corp. (SAIC) and Schmidt Associates, Inc. (Appendix A includes a description of the contractors' qualifications.) Other team members were Hank Gignilliat, DAIM-FDF-UE and John Lanzarone, HQUSACE. Also critical to the investigation were coordination and information gathering efforts by the Pacific Ocean Division (POD) and Alaska District Corps of Engineers and Fort Wainwright Directorate of Public Works staff. The team made an independent technical assessment of the FWA CHPP. In this work, POD and ERDC-CERL augmented the field data and quick analysis of the first study by detailing the "Heating-Only" solution to the current CHPP modernization strategy during the development of 1391s for implementing the interim solution.

Scope

This study was undertaken to assess future heating and electricity requirements of FWA. This assessment would help FWA develop plans to meet its energy needs based on how long the existing CHPP would continue to satisfy FWA heat loads, and on how large the electrical supply and backup equipment must be to meet future electrical loads. This results of this study, which was based on data that produced results with relative accuracy, were meant to enable future planning, and not to determine final design.

Mode of Technology Transfer

The results of this work have been transmitted to Fort Wainwright, USARAK, USARPAC, and ACSIM for implementation. This report will be made available through the World Wide Web (WWW) at URL:

www.cecer.army.mil

2 Plant Overview

Summary of Existing Mechanical Systems

The Central Heat and Power Plant (CHPP) at Fort Wainwright, AK (FWA) is a coal-fired steam boiler plant that currently provides a majority of the steam and electricity to the Installation. The CHPP consists of six 150,000 lb/hr coal-fired stoker boilers that produce 400 psig steam at 650 °F. Two original boilers are no longer functional and have been abandoned in-place. The CHPP has five steam turbine generators. There are three 5 MW condensing turbine generators, a 2 MW condensing turbine generator, and a 5 MW noncondensing turbine generator. The 2 MW condensing turbine generator, Turbine No. 2, has been down for 30 years and is not economical to repair. It has been abandoned in place.

The steam is used to run the turbines for electrical generation and to provide heating to the Installation through a network of utilidors. The boilers provide steam at a pressure of 400 psig and steam is supplied to the utilidors at 100 psig. The utilidors provide some of the utilities (the distribution piping) to the buildings on the Installation including steam for heating, potable water, and sewer. The system has been designed so that the radiant heat from the steam piping provides freeze protection to the potable water and sewer during the extreme cold winter temperatures. If these services freeze during the winter, the Installation will become nonfunctional and all personnel would need to be evacuated.

Turbine condenser cooling water is provided from a cooling pond located adjacent to the CHPP. During the winter months, this pond creates an ice fog that moves across the valley. This fog significantly reduces visibility on a nearby highway, which results in an unsafe situation for vehicles. To address this issue, a plan is underway to install an air-cooled condenser and eliminate the pond as a source of cooling.

Coal is delivered to the plant by rail. The coal is mined near Healy, AK and is purchased from the Usibelli Coal Mine, Inc. FWA maintains a coal pile with a 90 day minimum inventory.

Summary of Existing Electrical Systems

The plant was originally served internally from two independent 2400-volt switchgear line-ups. When the CHPP was modified in 1950, two additional independent feeds were added from the 12,470-volt line-up. This left the plant with four individual services, the failure of any one of which could seriously cripple the power plant—either reducing its capacity by one-half or taking it off-line totally. An improvement project now under construction will replace the separate 2,400-volt line-ups with one double-ended 4,160-volt switchgear line-up. After this project is completed, the plant will be served internally from 4,160-volt power and 12,470 volt power.

Circuit protection is provided by protective relays in the switchgear line-up, with distribution protection on the distribution circuits. All circuit breakers are Magna-blast type breakers located inside the turbine building on the operating floor level. Although Magna-blast type breakers were the industry standard from the 1950s to the late 1970s, the protective relays are seriously outdated and some are constantly out of service for repair. Demand metering and ammeters on some of the cubicles are currently out of service. Additionally, two of the central control system transducers are out of calibration and yield unreliable data.

Summary of Existing Control System

The boilers and turbine generator sets are currently controlled by a Westinghouse distributed control system. Installed approximately 6 years ago (1996) the Westinghouse WDPF control system was funded under HSQ PO No. 2763239-8419, as Westinghouse project D3904. Westinghouse introduced the WDPF system family in 1982 and introduced its replacement in 1997. The system is comprised of approximately 7000-8000 points of monitoring and control, which covers both the boiler side and the turbine generator side. The control points are evenly divided between the steam generation side and the turbine generator side. The system head end computation and control is running on an IBM OS/2 operating system platform installed on Intel 386 class personal computers (PCs). The OS/2 system has major limitations in retrieving data. It was reported in the field that this system cannot write to CD writers, only to floppy disk drives, because drivers were never written for this version of OS/2. This makes data transfer and retrieval very slow. The marginal performance of this system causes a large amount of time to be spent retrieving data, which delays other tasks.

Point interface is handled by a series of distributed control cabinets that are networked together and connected to the head end via a proprietary network configuration. These network cards are beginning to fail on a regular basis and replacements are difficult to obtain.

Summary of Existing Projects

Major projects that are underway at the CHPP are the refurbishment of the boilers and the addition of baghouses for each boiler. Another project currently underway is the replacement of the separate 2,400-volt line-ups with one double-ended 4160-volt switchgear line-up. After this project is complete, the plant will be served internally from 4,160-volt power and 12,470 volt power.

Summary of Planned Projects

The major planned project is the conversion of the cooling system from a cooling pond to an air-cooled condenser. This project is the result of a need to eliminate the ice fog problems that create a driving hazard on the nearby highway. This project is currently on hold pending the outcome of the project recommended in this report.

Reliability

FWA Mechanical Systems

Table 1 summarizes the CHPP outages as recorded in the plant operator's logbook. In several of the cases, an outage was noted by the plant operator, but details of the outage were not included.

FWA Electrical Infrastructure

Tables 2 to 4 summarize FWA line bumps and feeder trips as recorded in the plant operator's logbook.

Table 1. CHPP outages.

Date	Description	Start	End	Duration (hr:min)
12/13/2000	Plant Down (UPS Outage)	15:58	16:01	0:03
1/30/2001	Plant Outage			
2/23/2001	Blown Superheater Tube (open feeders 11,22,23,24) Loose Plant @ 16:34	13:40	20:08	6:28
3/29/2001	Loose Plant and UPS			
6/18/2001	Plant Down (GVEA looses North Pole and Chena 5)			0:00
3/17/2002				
4/8/2002				
4/24/2002				
6/7/2002	GVEA Out (Frequency=57.77)	16:30		
6/25/2002				
Number of Occurances				10
Total Outage Time				6:31

Table 2. 1999 line bumps and feeder trips.

Date	Description	Start	End	Duration (hr:min)
5/29/1999	Healy #2 Tripped off line	20:45	20:46	0:01
6/27/1999	Line Problem @ Glass Park	0:44	0:45	0:01
7/13/1999	#12 Feeder Trip	8:42	8:43	0:01
7/18/1999	#15 Feeder Trip	8:27	9:36	1:09
7/30/1999	GVEA lost tie between Wasilla and Willow	7:00	7:01	0:01
9/11/1999	Healy #2 Tripped off line	12:30	0:30	1:00
10/27/1999	#5 Bulga Tripped	14:00	14:01	2:00
10/27/1999	#22 Feeder Tripped	16:56	16:57	0:01
11/15/1999	#15 Switch Tripped			0:01
11/17/1999	Unit #5 in Achorage went down	11:10	11:11	0:01
12/7/1999	Truck hit pole on #23 Feeder	9:03	10:20	1:17
12/18/1999	#24 Feeder Tripped	13:16	1:17 PM	0:01
Number of Occurances				12
Total Outage Time				5:34

Table 3. 2000 line bumps and feeder trips.

Date	Description	Start	End	Duration (hr:min)
1/17/2000	#14 Feeder Tripped	17:45	17:47	0:02
1/18/2000	#11 Feeder Tripped (Transformer and down line)	7:22	7:57	0:35
1/28/2000	#13 Feeder Tripped	17:43	19:07	1:24
2/2/2000	Bumps due to high winds on the intertie			0:01
2/14/2000	#11 Feeder Tripped	12:46	12:47	0:01
3/6/2000	Unit lost in Anchorage	2:45	2:46	0:01
3/8/2000	#10 Feeder Tripped	12:37	12:37	0:00
4/4/2000	#13 Feeder Tripped	12:14	12:15	0:01
4/22/2000	#11 Feeder Tripped (blown transformer)	7:30	8:37	1:07
4/23/2000	Bumps due to loss of units in Anchorage	12:59	13:03	0:04
4/29/2000	#11 Feeder Tripped	8:59	9:01	0:02
5/26/2000	#10 Feeder Tripped (Tree)	8:45	8:47	0:02
5/31/2000	#11 Feeder Tripped	10:33	11:20	0:47
6/8/2000	Bump (Anchorage looses unit)	15:58	15:59	0:01
8/6/2000	Bump (blown relay on 69 line)	12:30	12:31	0:01
8/15/2000	#10 Feeder Tripped	23:24	23:25	0:01
8/20/2000	#24 Feeder Tripped	14:55	14:57	0:02
9/24/2000	#22 Feeder Tripped	15:08	15:09	0:01
9/30/2000	#24 Feeder Tripped	11:19	11:28	0:09
10/6/2000	#24 Feeder Tripped (Replace Fuse)	12:00		
12/13/2000	Plant Down (UPS Outage)	15:58	16:01	0:03
12/19/2000	#23 Feeder Tripped	12:38	12:40	0:02
Number of Occurances				22
Total Outage Time				4:27

Table 4. 2001 line bumps and feeder trips.

Date	Description	Start	End	Duration (hr:min)
1/15/2001	#14 Feeder Tripped	6:35	6:36	0:01
1/15/2001	#22 Feeder Tripped	12:45	12:46	0:01
1/15/2001	#23 Feeder Tripped (down line)	4:36	6:35	1:59
1/28/2001	Bump (Anchorage looses generator)	2:10	2:11	0:01
2/23/2001	Blown Superheater Tube (open feeders 11,22,23,24) Loose Plant @ 16:34	13:40	20:08	6:28
4/4/2001	Loose Plant (UPS)			0:00
6/2/2001	#10 Feeder Tripped	6:57	6:58	0:01
6/18/2001	Plant Down (GVEA looses North Pole and Chena 5)			0:00
7/1/2001	#22 Feeder Shutdown (Damaged Pole)	9:01	15:13	6:12
7/28/2001	Bump (GVEA)	7:28	7:29	0:01
8/13/2001	#22 Feeder Tripped	13:35	13:36	0:01
1/18/2001	#10 Feeder Tripped	1:09	1:10	0:01
8/18/2001	#10 Feeder Tripped	2:10	3:50	1:40
8/22/2001	#10 Feeder Tripped	7:10	8:03	0:53
8/22/2001	#10 Feeder Tripped	14:14	14:15	0:01
8/23/2001	#10 Feeder Tripped	12:00	12:01	0:01
8/23/2001	#10 Feeder Tripped	13:26	13:27	0:01
10/1/2001	Drop #11 Feeder for load shed due to Boiler #4 problems	0:24	0:32	0:08
11/1/2001	#23 Feeder Tripped	10:02	10:17	0:15
11/1/2001	#22 Feeder Tripped (down line)	13:23	15:13	1:50
12/4/2001	Boiler #3 blows header			
12/5/2001	Boiler #4 lost stoker	19:30		
Number of Occurances				22
Total Outage Time				19:35

3 GVEA Power System Reliability

Historical Outages

GVEA service reliability is determined by the number, magnitude, and duration of customer outages. While high reliability is critical to Fort Wainwright, the temperature levels experienced in the Fairbanks area make reliability even more critical than for most utilities. Temperatures in interior Alaska have been recorded from –78 °F to 93 °F, but typically average from –22 °F to –2 °F in the winter and from 50 °F to 72 °F in the summer. Loss of electrical power during the cold winter months, even for 4 to 6 hrs, can have severe impacts. At –20 °F, a typical residence that was at 70 °F before an outage would generally begin freezing in 9 hrs and be totally frozen in 23 hrs. Table 5 lists the most recent outage history for GVEA's distribution line to Fort Wainwright.

Tables 6 to 8 list GVEA's power outage details over the past 3 years. The values represent details for the various types of outages. The data shows that the average GVEA customer experiences 3.6 to 5.1 outages per year with the average outage time ranging from 26 to 35 minutes per occurrence.

GVEA's Supervisory Control and Data Acquisition (SCADA) computer system allows them to remotely control all turbines and substation breakers as far south as Cantwell. This reduces the number of times a line crew must be dispatched to investigate a system disturbance. SCADA also provides cost-based dispatching; minute-by-minute loads are tracked to obtain the next megawatt of power at the least cost. To prevent over-capacity on distribution lines, GVEA limits the electrical loads to 50 percent of design capacity.

Power Outage Prevention

GVEA uses a load-shedding approach to handle supply or distribution disruptions. They rotate customer load loss to share the burden. Certain critical facilities such as hospitals, airports, and power stations are never cut off. GVEA has expressed confidence that they can provide reliable power to FWA based on their current system design, reserve capacity, and historical reliability data.

Table 5. Recent GVEA outage history for distribution line to FWA.

Date of Outage	Duration of Outage
7 June 2002	34 minutes
17 March 2002	3 minutes
18 June 2001	16 minutes
11 September 2000	2 minutes

Table 6. 1999 summary of average GVEA power outages.

	Number of Outages	Customers Affected	Customer Hours	Minutes per Customer*
Category A: Power Supply				
Unit Trip	31	230,429	13,525.53	22.223
Transmission	14	77,971	13,628.76	22.392
Recloser	0	0	0.00	0.000
Silos Event	13	76,706	7,296.07	11.988
	19	**131,373**	**23,626.00**	**38.818**
Category B: Extreme Storm				
Wind	115	22,129	24,734.53	40.639
Snow	32	2,054	265.12	0.436
Rain	0	0	0.00	0.000
Flood/Lighting	34	4,439	6,859.90	11.271
	138	**11,207**	**31,786.77**	**52.226**
Category C: Prearranged				
Planned	162	9,181	2,372.36	3.898
	145	**4,485**	**2,273.35**	**3.735**
Category D: Other				
Trees	78	12,004	5,545.77	9.1118
Animals	266	19,755	2,672.09	4.3903
Teardown	70	12,044	9,140.72	15.0184
Equipment	166	34,166	26,311.22	43.2300
	536	**27,316**	**43,133.68**	**70.8697**
Total Outages	**838**	**174,381**	**100,819.87**	**165.6496**

Avg. Number of Customers: ***36,518***

* Based on total number of customers

Hours Per Customer	2.761
Interruptions per Customer	4.775
Minutes per Interruption	34.690

The average customer experienced 4.8 interruptions in electric service for at total outage time of 2.76 hours. The average duration of each interruption was 35 minutes.

Table 7. 2000 summary of average GVEA power outages.

2000 - GVEA Outage Summary

	Number of Outages	Customers Affected	Customer Hours	Minutes per Customer*
Category A: Power Supply				
Unit Trip	22	112,111	9,854.47	15.998
Transmission	17	157,420	43,217.90	70.159
Recloser	19	10,504	11.68	0.019
Silos Event	7	30,723	2,249.32	3.651
	25	**161,380**	**50,052.09**	**81.253**
Category B: Extreme Storm				
Wind	18	3,655	198.33	0.322
Snow	62	21,832	1,938.98	3.148
Rain	9	489	335.32	0.544
Flood/Lighting	21	1,563	304.05	0.494
	82	**1,798**	**31,786.77**	**51.602**
Category C: Prearranged				
Planned	303	25,574	3,419.70	5.551
	272	**6,570**	**3,136.00**	**5.091**
Category D: Other				
Trees	84	22,681	2,962.88	4.810
Animals	255	62,716	4,790.50	7.777
Teardown	63	8,255	1,921.48	3.119
Equipment	200	57,521	19,379.47	31.460
	513	**20,125**	**28,385.48**	**46.080**
Total Outages	**892**	**189,873**	**84,300.60**	**136.852**

Avg. Number of Customers: ***36,960***

* Based on total number of customers

Hours Per Customer	2.281
Interruptions per Customer	5.137
Minutes per Interruption	26.639

The average customer experienced 5.1 interruptions in electric service for at total outage time of 2.28 hours. The average duration of each interruption was 27 minutes.

Table 8. 2001 summary of average GVEA power outages.

	Number of Outages	Customers Affected	Customer Hours	Minutes per Customer*
Category A: Power Supply				
Unit Trip	14	97,226	10,546.61	16.935
Transmission	6	22,446	2,447.98	3.931
Recloser	15	8,963	110.65	0.178
Silos Event	46	253,981	16,050.87	25.773
	21	**106,448**	**20,241.01**	**32.501**
Category B: Extreme Storm				
Wind	18	5,073	1,436.35	2.306
Snow	4	709	350.53	0.563
Rain	1	3	3.00	0.005
Flood/Lighting	9	666	56.15	0.090
	23	**1,073**	**1,840.58**	**2.955**
Category C: Prearranged				
Planned	285	23,565	29,508.50	47.382
	248	**8,671**	**29,188.71**	**46.868**
Category D: Other				
Trees	99	38,475	7,974.23	12.8042
Animals	255	62,690	4,347.30	6.9804
Teardown	44	7,379	1,119.38	1.7974
Equipment	171	35,967	14,486.77	23.2613
	438	**19,696**	**27,579.85**	**44.2848**
Total Outages	**730**	**135,888**	**78,850.16**	**126.6093**
Avg. Number of Customers:		***37,367***		

* Based on total number of customers

Hours Per Customer	2.110
Interruptions per Customer	3.637
Minutes per Interruption	34.816

The average customer experienced 3.6 interruptions in electric service for at total outage time of 2.11 hours. The average duration of each interruption was 34 minutes.

GVEA employs “aggressive” automatic under-frequency relaying to automatically shed load as the means of reestablishing load-generation balance within time constraints necessary to avoid system collapse. While this technique causes some service interruptions, it has been shown to reduce costs and lower rates for GVEA customers.

During normal operations, GVEA’s load shedding bias is 10 MW / 0.1 Hz. When cut off from import power from Wasilla (Anchorage), their load bias decreases to 2.5 MW / 0.1 Hz. GVEA’s minimum frequency set point is 58.7 Hz. Load shedding will occur within approximately 2 seconds to maintain system balance.

A worst-case occurs when the Fairbanks-Healy intertie is lost. Under this circumstance, all power generation must come from GVEA's Fairbanks plants, which amounts to approximately 231MW of capacity. At peak winter load of 185 MW, the reserve margin is about 46 MW. If, for example, the North Pole plant goes down, GVEA can only feed about 97 MW. Load shedding via automatic underfrequency relaying could only reduce load by 32.5 MW ([60-58.7]/0.1x2.5) before the entire system would likely fail. While such an event has a low probability of occurrence, it is still a possibility. Completion of a parallel transmission intertie into Fairbanks, as discussed below will virtually eliminate such a catastrophic event.

GVEA Backup Power Generation

GVEA maintains oil-fired combustion turbine generators and diesel engine generators to provide emergency backup generation for their system. These units are located in Fairbanks at the Chena Power Plant and at the Zehnder facility. Total winter backup capacity is approximately 75 MW and summer capacity is 65 MW. Start-up time for these units is:

- large combustion turbine generators – 15 minutes from cold start
- smaller combustion turbine generators – 10 to 15 minutes from cold start
- stationary diesel engine generators – 8 minutes from cold start.

All backup generators are housed in heated buildings.

Supply and Transmission Issues*

GVEA has adequate "Firm" generation capacity to meet peak load with even the largest generation unit off line. However, the loss of the existing intertie (between Healy and Fairbanks) would disconnect 100 MW of power generated at Healy No. 1 and Anchorage. If this line is out of service, GVEA must start and run most of their local Fairbanks generation units to provide power to its members. This situation happened as recently as 25 September 1997, and all available generators in the Fairbanks area were run to meet the loads. While they should still have a reserve

* The discussion focuses on GVEA as the power supplier since it is currently supplying power to the installation and has the required capacity to meet the installation's load requirements. This does not preclude the possibility of alternative power providers such as Aurora Energy. However, Aurora currently is committed to selling 95 percent of its power to GVEA.

margin of 20 percent at winter peak load (Table 6), the loss of only one of the 60 MW turbines at the North Pole Station would exceed the reserve margin. Under such circumstances GVEA would have to shed load and resort to a "rolling blackout" to maintain system balance. Under the worst-case scenario, the loss of a large generation unit, such as the North Pole plant, could potentially result in the collapse of the system. However, completion of the Northern Intertie will provide a redundant line to deliver power to Fairbanks, which makes the worst-case scenario highly unlikely.

Conclusions on GVEA Reliability

- A review of FWA plant information from 1999 – 2002 indicates an average of 3-5 GVEA-related line bumps per year, each lasting under 1 minute. In addition, outages lasting from 2 minutes – 34 minutes on the distribution line serving FWA were noted in the 2000 – 2002 time frame. This compares favorably with the disruptions associated with the FWA distribution system.
- Typical customers on the GVEA system experienced 3.6 – 4.8 outages annually, with each outage averaging 26 to 35 minutes in the 1999 – 2001 time frame.
- Current plans to strengthen the GVEA system including the parallel intertie into Fairbanks will eliminate major problems that could be caused by loss of the Fairbanks-Healey intertie.
- Battery backup (20 MWh) of GVEA generators will help ensure against service disruptions.

Conclusion

GVEA should be able to provide power to the Installation reliably.

4 FWA Existing Loads

Electrical

Table 9 summarizes the electricity generated by the FWA CHPP ("Generator") as well as the GVEA imports and exports in MWh. The GVEA numbers are measured at the substation and do not include electricity transferred across the backdoor intertie.

The consumption of electricity varies seasonally, with the peak usage occurring during the winter months. Figure 1 shows the monthly totals for electricity generated by the CHPP and the net electric usage for FWA. Net usage is equal to the CHPP generation + GVEA Import – GVEA Export. The total net electric consumption by FWA between June 2001 and May 2002 was 90,783 MWh.

Table 10 and Figure 2 present the electrical generator loads for FWA based on FWA CHPP electrical data between May 2001 and April 2002. Hourly data was obtained for the peak day between May 2001 and April 2002, which was 6 November 2001. The average generator load for the day was 15.85 MW, and the data shows that the peak demand based on an hour average was 17.22 MW (Figure 3).

Heating

The total annual steam requirement for heating between June 2001 and May 2002 was 1,441,735 thousand pounds (klbs) (Savoie et al. 2003, p 8). To better characterize the heat load requirements for FWA, the CHPP plant heating data were analyzed on a daily basis and simple daily averages were calculated to identify representative heating rates (Table 11 and Figure 4).

Hourly data was obtained for the peak day between May 2001 and April 2002, which was 6 November 2001. The average demand for the day was 253 klb/hr. Figure 5 shows that the peak demand based on an hour average was 265 klb/hr (Savoie et al. 2003, p 14).

Table 9. FWA and GVEA electrical generation summary.

Month	Generator			GVEA Import		GVEA Export	
	Monthly Total MWh	Daily Average MWh	Hourly Avg MWh	Monthly Total	Daily Average	Monthly Total	Daily Average
Apr-01	6,355.0	211.8	8.8	640.9	21.4	374.8	12.5
May-01	7,833.5	252.7	10.5	33.2	1.1	815.4	26.3
Jun-01	6,300.0	203.2	8.5	13.9	0.4	842.1	27.2
Jul-01	5,737.1	185.1	7.7	34.2	1.1	780.3	25.2
Aug-01	5,884.0	189.8	7.9	113.2	3.7	808.8	26.1
Sep-01	5,981.4	199.4	8.3	185.3	6.2	493.7	16.5
Oct-01	8,181.2	263.9	11.0	588.1	19.0	196.4	6.3
Nov-01	8,923.5	297.5	12.4	443.7	14.8	567.0	18.9
Dec-01	9,368.1	302.2	12.6	639.1	20.6	408.7	13.2
Jan-02	10,109.2	326.1	13.6	213.6	6.9	596.1	19.2
Feb-02	9,195.5	328.4	13.7	237.2	8.5	643.7	23.0
Mar-02	9,453.9	305.0	12.7	154.3	5.0	720.2	23.2
Apr-02	7,650.3	255.0	10.6	427.8	14.3	612.6	20.4
May-02	7,605.0	245.3	10.2	500.8	16.2	487.5	15.7

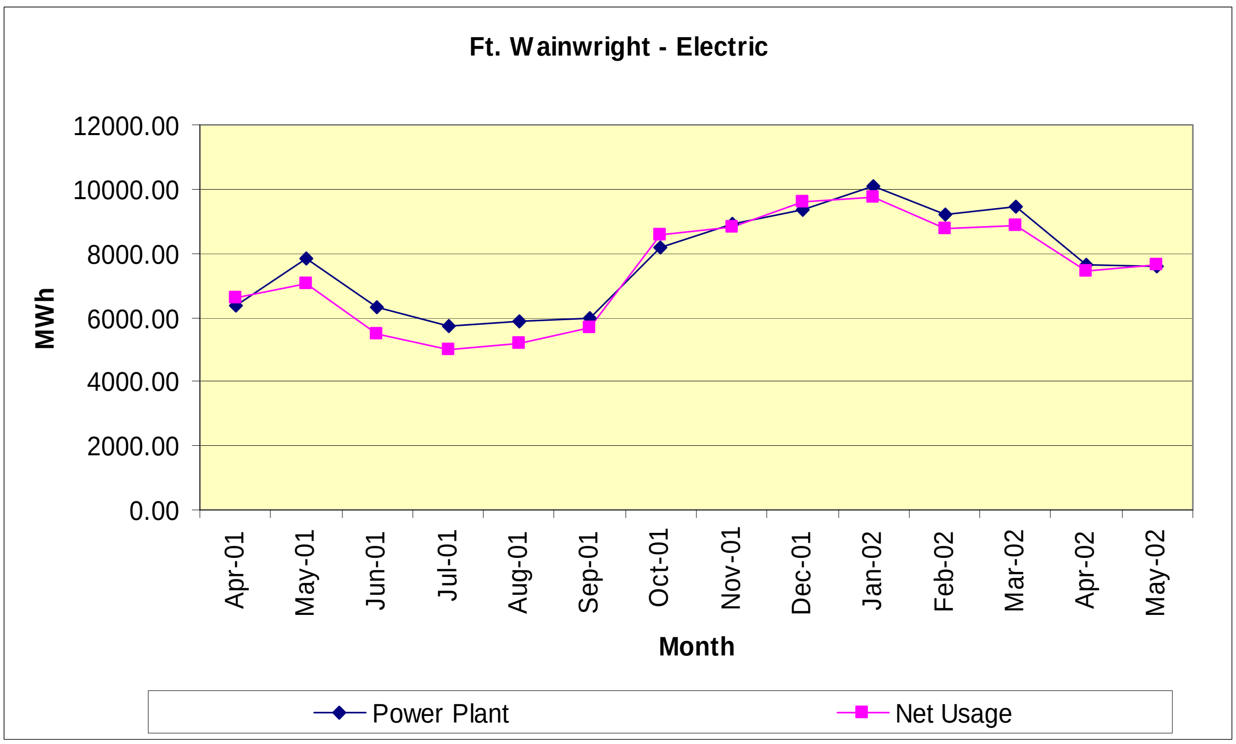

Figure 1. FWA electrical generation and usage.

Table 10. FWA monthly electrical demand.

Generator Loads (MW)		
Month	Average	Max
May	10.5	11.5
June	8.5	11.4
July	7.7	8.5
Aug	7.9	8.5
Sept	8.3	11.3
Oct	10.9	13.9
Nov	12.4	15.8
Dec	12.5	14.9
Jan	13.5	15.5
Feb	13.7	14.9
Mar	12.7	14.0
Apr	10.6	12.9

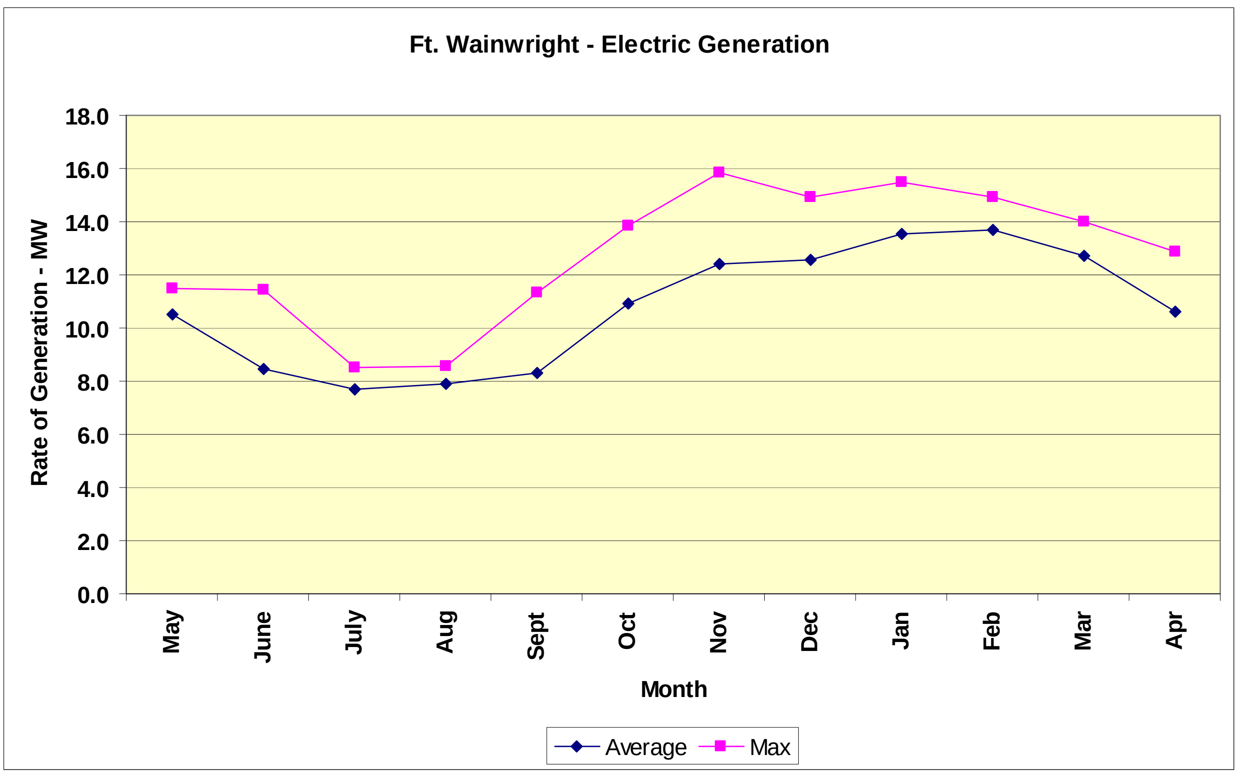

Figure 2. FWA monthly electrical demand.

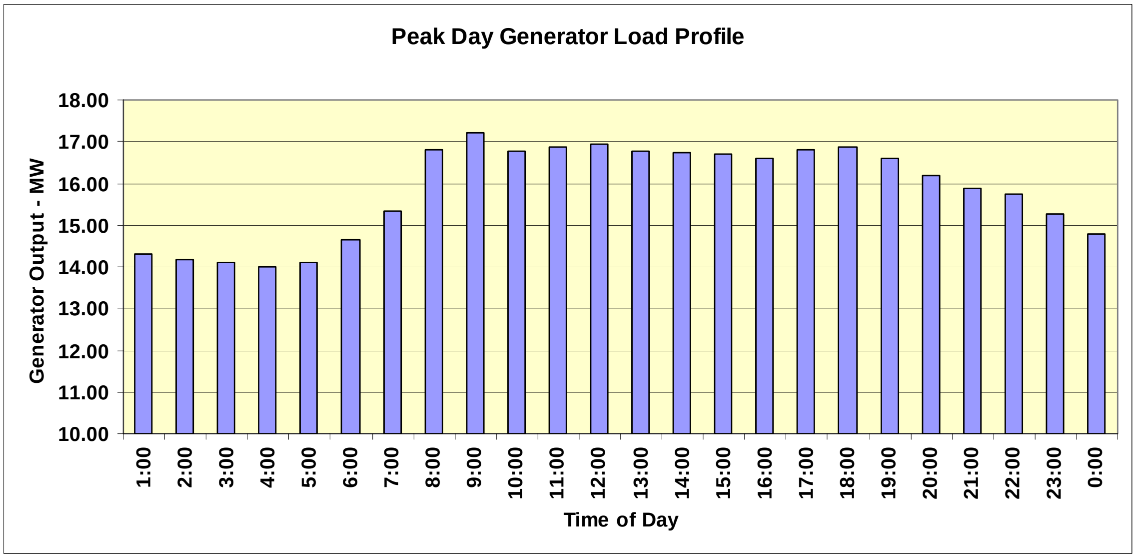

Figure 3. Peak day generator load profile.

Table 11. Heating loads–daily and hourly rates.

Month	Daily		Hourly	
	Average	Max	Average	Max
May	3,689.0	4,892.9	153.7	203.9
June	2,833.9	4,467.9	118.1	186.2
July	3,311.6	4,241.3	138.0	176.7
Aug	3,216.5	3,469.4	134.0	144.6
Sept	3,514.1	3,928.5	146.4	163.7
Oct	3,636.8	5,769.5	148.7	240.4
Nov	5,291.6	6,525.8	220.5	271.9
Dec	4,585.2	5,306.3	191.1	221.1
Jan	3,949.9	5,062.5	164.6	210.9
Feb	3,895.6	4,413.6	162.3	183.9
Mar	3,422.7	3,909.2	142.6	162.9
Apr	3,286.8	3,938.5	137.0	164.1

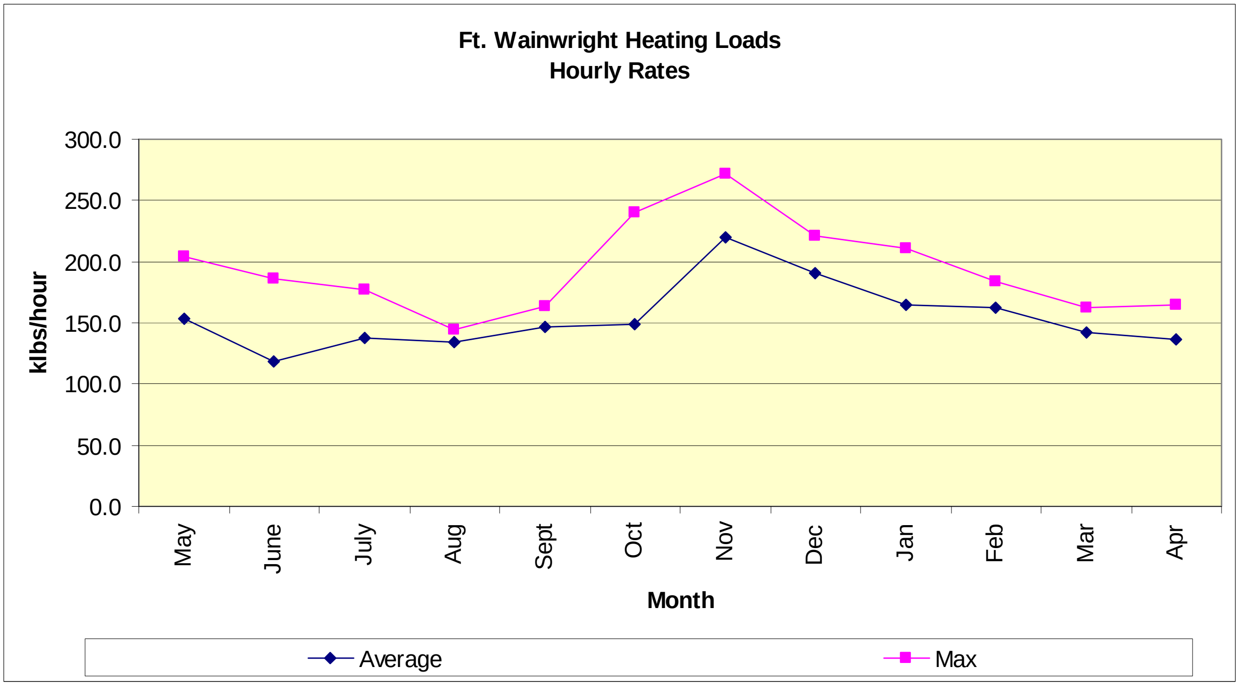

Figure 4. Heating loads – hourly rates.

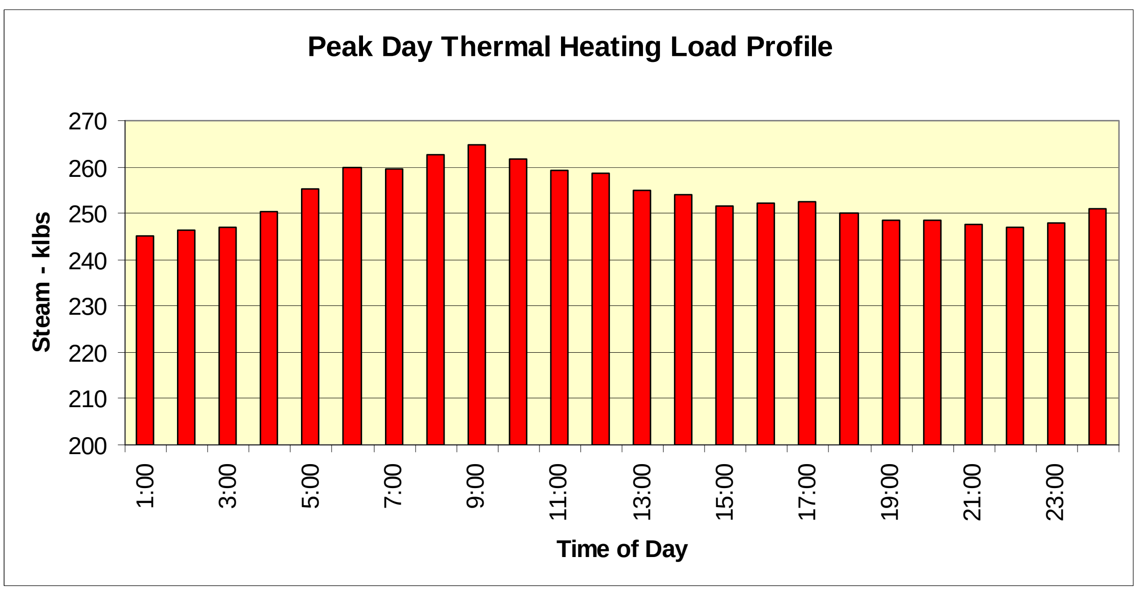

Figure 5. Peak day thermal heating load profile.

5 FWA Load Growth

The load growth described in this study is conceptual in nature, is based on data available as of October 2002, and is intended to support future planning as of that date. It is not intended to serve as a design tool. A subsequent study* has produced load growths that supersede those described here.

Planned Projects

Table 12 summarizes the planned projects for FWA as of October 2002. The building data listed in Table 12 is based on the FWA Master Plan. Steam usage is based on the net heating value of 1246 Btu/lb of steam. The net impact on FWA electric and heating loads are estimated based on typical loads for types of facilities in the Alaska climate (Table 13). The loads are based on 2001 operational data from the FWA Birchwood Housing area, then extrapolated for other building types using the U.S. Department of Energy (DOE) commercial building energy consumption survey (CBECS).

Electrical

The monthly forecast of electrical load growth was estimated using the peak electric load profile for the existing FWA electrical loads as the base year case and estimating that, on average, the new buildings will have a similar annual load profile. Figure 6 shows the monthly peak load forecast.

The large demand increase in 2006 is mostly attributed to the new hospital. This demand includes the existing hospital in operation while the new hospital is tested and verified. In 2007, the model drops the entire load attributable to the existing hospital. By the end of 2010, the peak electrical demand for FWA will be 25.4 MW.

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* Curtis L. Bagnall, Anthony C. Taladay, John L. Vavrin, William T. Brown, and Alexander M. Zhivov, *Joint Long-Range Energy Study for Greater Fairbanks Military Complex*, ERDC/CERL Draft TR(ERDC-CERL, Champaign, IL, September 2004).

Also, note that the project peak demand will exceed the capacity of the existing CHPP in 2006. Figure 7 shows the projected annual electric requirements for FWA. The total annual electric consumption is projected to double between 2002 and 2010.

Heating

The monthly forecast of steam heating load growth was estimated using the peak heating steam load profile for the existing FWA thermal loads as the base year case and estimating that on average the new buildings will have a similar annual load profile. Figure 8 shows the monthly peak load forecast. The largest impact to the heat load growth is the addition of new family housing.

Figure 9 shows the projected annual steam heating requirements for FWA. Total annual steam heating consumption is projected to increase by approximately 50 percent between 2002 and 2010 at an average rate of 5.5 percent annually.

Table 12. FWA planned projects.

Beneficiary Occupancy Date (BOD)	Project #	Title	Square Footage	Demo	Net Square Footage	Net Electric Peak (kW)	Net Electric Annual (kWh)	Net Electric Monthly (kWh)	Steam Peak (lbs/hr)	Steam Annual klbs
Aug-02	53735	CHPP Cooling								
Oct-02	16809	Biathlon Live Fire								
Oct-02	54790	Birch Hill Trail and Lighting								
Mar-03	58146	Ice Rink Change House	3,600		3,600	18.0	63,072.0	5,256.0	101.1	535.0
Jun-03	54033	Assembly Building	12,500		12,500	62.5	219,000.0	18,250.0	351.0	1,857.5
Jun-03	50416	Barracks Upgrade	0		0	0.0	0.0	0.0	0.0	0.0
Jul-03	46098	Birch Hill Ski Lodge	7,140		7,140	35.7	125,092.8	10,424.4	200.5	1,061.0
Sep-03	56389	Utilidor Upgrade Phase 2			0	0.0	0.0	0.0	0.0	0.0
Oct-03	57961	Perimeter Boundary Fence			0	0.0	0.0	0.0	0.0	0.0
Oct-03	41585	Whole Neighboorhood Revitalization			0	0.0	0.0	0.0	0.0	0.0
Oct-03	58003	MOUT Upgrade (Montgomery)			0	0.0	0.0	0.0	0.0	0.0
Dec-03	44383	CHPP Emission Reduction			0	0.0	0.0	0.0	0.0	0.0
Jan-04	57341	Mission Support Training Facility - MSTF	115,000		115,000	2760.0	21,759,840.0	1,813,320.0	922.5	4,882.7
Jun-04	53387	Sniper Range	1,700		1,700	8.5	29,784.0	2,482.0	13.6	72.2
Jul-04	46292	AFH Replacement	48,015	149,976	-101,961	-611.8	-1,325,493.0	-110,457.8	-2044.8	-10,822.6
Aug-04	48777	CHPP Upgrade			0	0.0	0.0	0.0	0.0	0.0
Sep-04	55847	Modified MOUT - Shoot House	2,153	0	2,153	10.8	37,720.6	3,143.4	60.4	319.9
Sep-04	56922	ASP Upgrade - Lower	21,007	0	21,007	210.1	1,196,138.6	99,678.2	337.0	1,783.8
Sep-04	58056	UAV Maintenance Facility (DTA)	3,000		3,000	30.0	170,820.0	14,235.0	48.1	254.7
Oct-04	50504	Family Housing	127,180	162,041	-34,861	-209.2	-453,193.0	-37,766.1	-699.1	-3,700.3
Oct-04	57353	IBCT small BOF and 2 medium COF's	27,845	0	27,845	139.2	487,844.4	40,653.7	558.4	2,955.6
Oct-04	57354	Brigade Motor Pool - Phase 1	36,370	0	36,370	363.7	2,070,907.8	172,575.7	1021.1	5,404.7
Apr-05	57785	IBCT 200FA AFH	200,000	0	200,000	1200.0	2,600,000.0	216,666.7	4010.9	21,228.9
Apr-05	58187	IBCT 2 COF's	14,482	0	14,482	86.9	188,266.0	15,688.8	290.4	1,537.2
May-05	56388	JR NCO Housing Replacement	305,508		305,508	1833.0	3,971,604.0	330,967.0	6126.8	32,428.0
May-05	56921	Pallet Processing Facility	59,391	0	59,391	593.9	3,381,723.5	281,810.3	1667.5	8,825.7
Jul-05	42031	IPBC/Multipurpose Training Range	16,000		16,000	80.0	280,320.0	23,360.0	256.7	1,358.7
Oct-05	49938	Army Lodging	53,505	79,738	-26,233	-157.4	-341,029.0	-28,419.1	-526.1	-2,784.5
Nov-05	56951	Alert Holding Area	96,237		96,237	962.4	5,479,734.8	456,644.6	2702.0	14,301.1
Apr-06	53401	Battle Area Course	7,262		7,262	72.6	413,498.3	34,458.2	203.9	1,079.2
Apr-06	58551	Brigade Motor Pool - Phase 2	66,000	0	66,000	660.0	3,758,040.0	313,170.0	1058.9	5,604.4
Sep-06	16716	Modified Record File	2,000	0	2,000	20.0	113,880.0	9,490.0	56.2	297.2
Sep-06	56693	Combined Arms Collective Training	3,500	0	3,500	35.0	199,290.0	16,607.5	98.3	520.1
Oct-06	34810	Bassett Hospital Replacement	255,159	155,226	99,933	1499.0	9,848,397.2	820,699.8	2805.8	14,850.3
Oct-06	46789	CIS Barraks Phase 4A + COFs	87,657	0	87,657	525.9	1,139,541.0	94,961.8	1757.9	9,304.3
Oct-06	47125	CIS Barraks Phase 4B + COFs	89,132	0	89,132	534.8	1,158,716.0	96,559.7	1787.5	9,460.9
Oct-06	47673	AFH Replacement	46,800	54,626	-7,826	-47.0	-101,738.0	-8,478.2	-156.9	-830.7
Oct-07	46790	CIS Barracks Phase 4C + COFs	63,155	0	63,155	378.9	821,015.0	68,417.9	1266.5	6,703.6
Oct-07	56550	AFH Replacement	60,019	74,988	-14,969	-89.8	-194,597.0	-16,216.4	-300.2	-1,588.9
Oct-07	58048	IBCT Barracks	55,800	0	55,800	334.8	725,400.0	60,450.0	1119.0	5,922.9
Oct-07	58188	Tanana River Bridge Infrastructure			0	0.0	0.0	0.0	0.0	0.0
Oct-08	14453	ACES Facilities, Library/MOS/Ed Center	26,700	0	26,700	133.5	467,784.0	38,982.0	428.4	2,267.3
Oct-08	46290	AFH Replacement	138,720	142,952	-4,232	-25.4	-55,016.0	-4,584.7	-84.9	-449.2
Oct-08	55704	Upgrade Transient Quarters	52,333		52,333	314.0	680,329.0	56,694.1	1049.5	5,554.9
May-09	29554	Replace Hanger #2	54,508	52,594	1,914	19.1	108,983.2	9,081.9	53.7	284.4
May-09	41751	Replace Hanger #3	54,508	52,594	1,914	19.1	108,983.2	9,081.9	53.7	284.4
Oct-09	55344	MP Station	4,000	0	4,000	20.0	70,080.0	5,840.0	64.2	339.7
		Totals	**2,217,886**	**924,735**	**1,293,151**	**11,821**	**59,204,739**	**4,933,728**	**26,660**	**141,104**

Table 13. Annual energy use intensity (EUI) estimate.

Type of Facility	Electricity			Heating	
	Watts/sf	watt-hrs/sf/yr	Load Factor	BTU/hr/sf	BTU/sf/yr
Computer Center	20	157,680	0.90	10	52,900
Hospital	15	98,550	0.75	35	185,100
Industrial	10	56,940	0.65	35	185,100
Housing	6	13,000	0.25	25	132,250
Offices	5	17,520	0.40	20	105,800

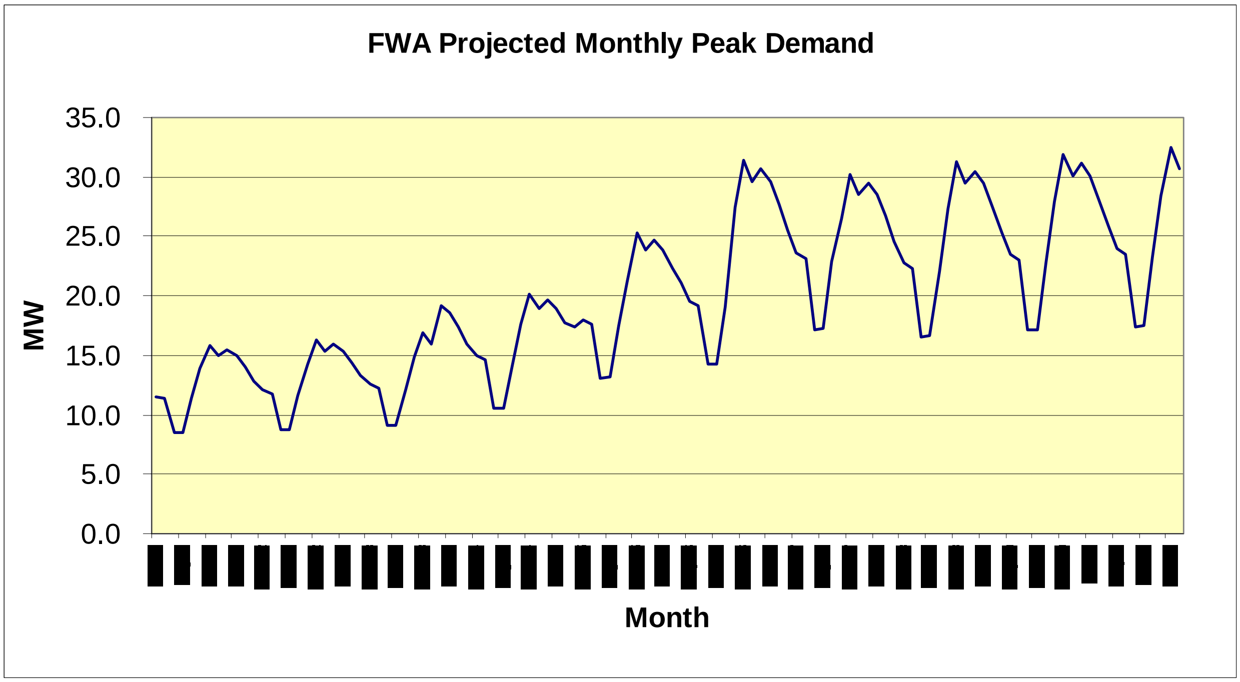

Figure 6. FWA projected monthly peak demand.

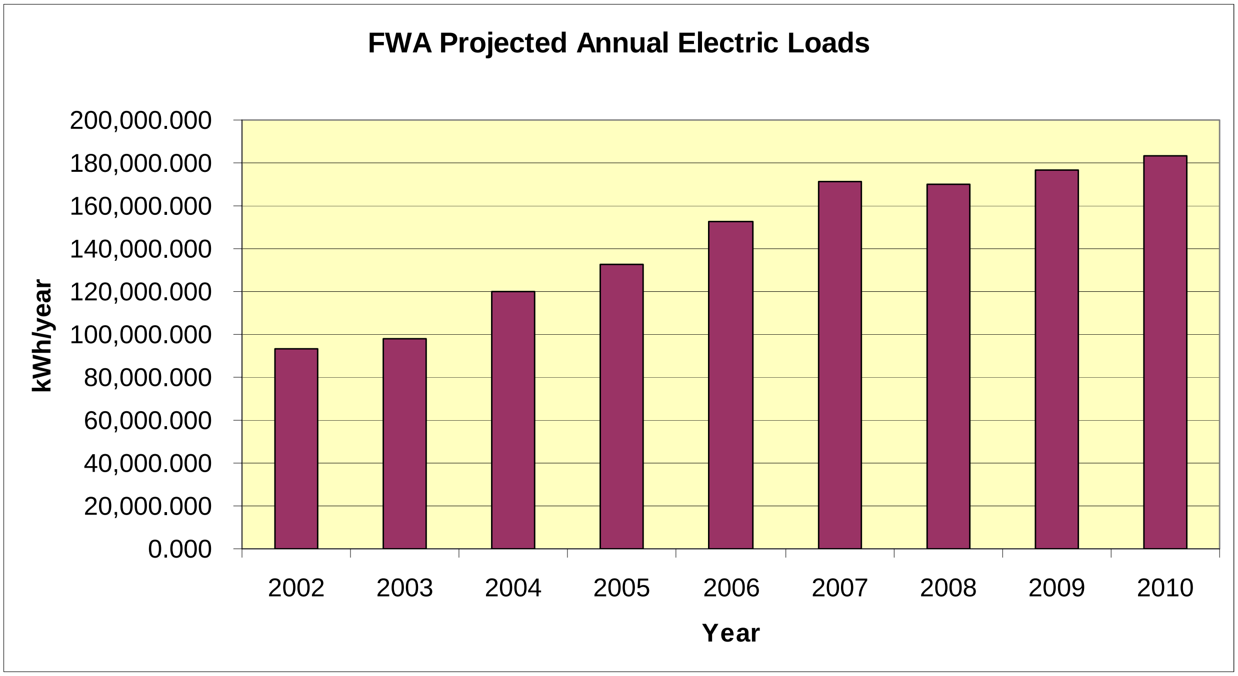

Figure 7. FWA projected annual electric loads.

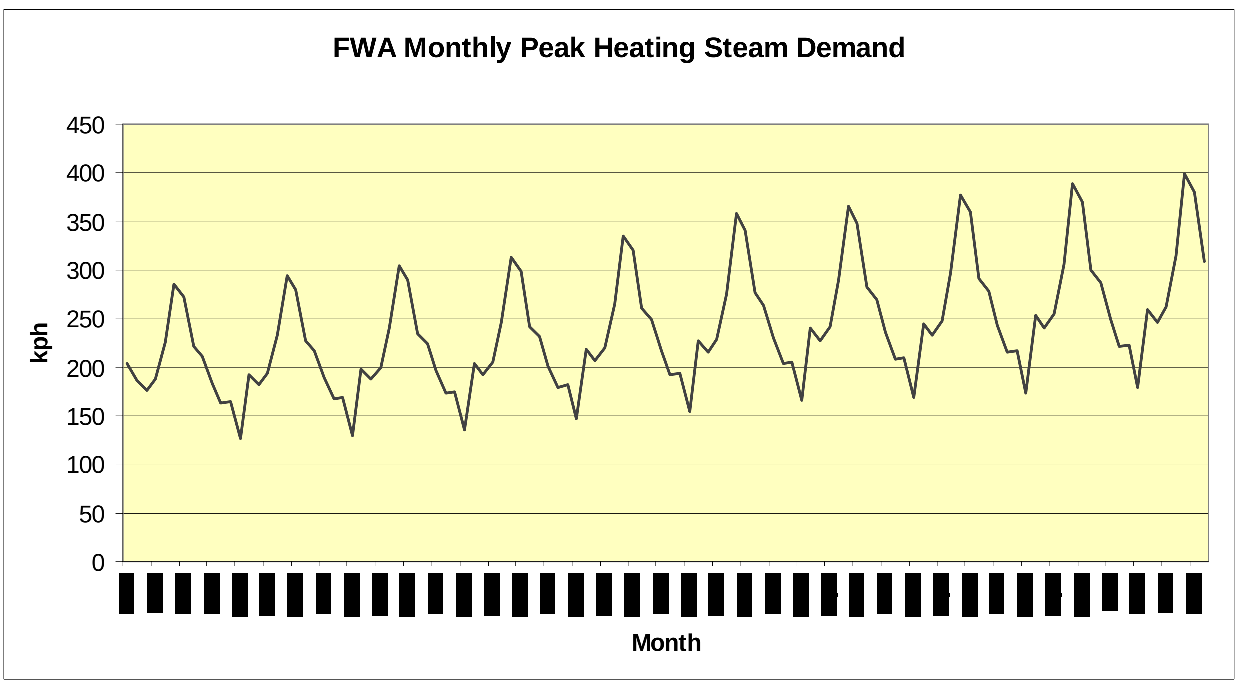

Figure 8. FWA monthly peak heating steam demand.

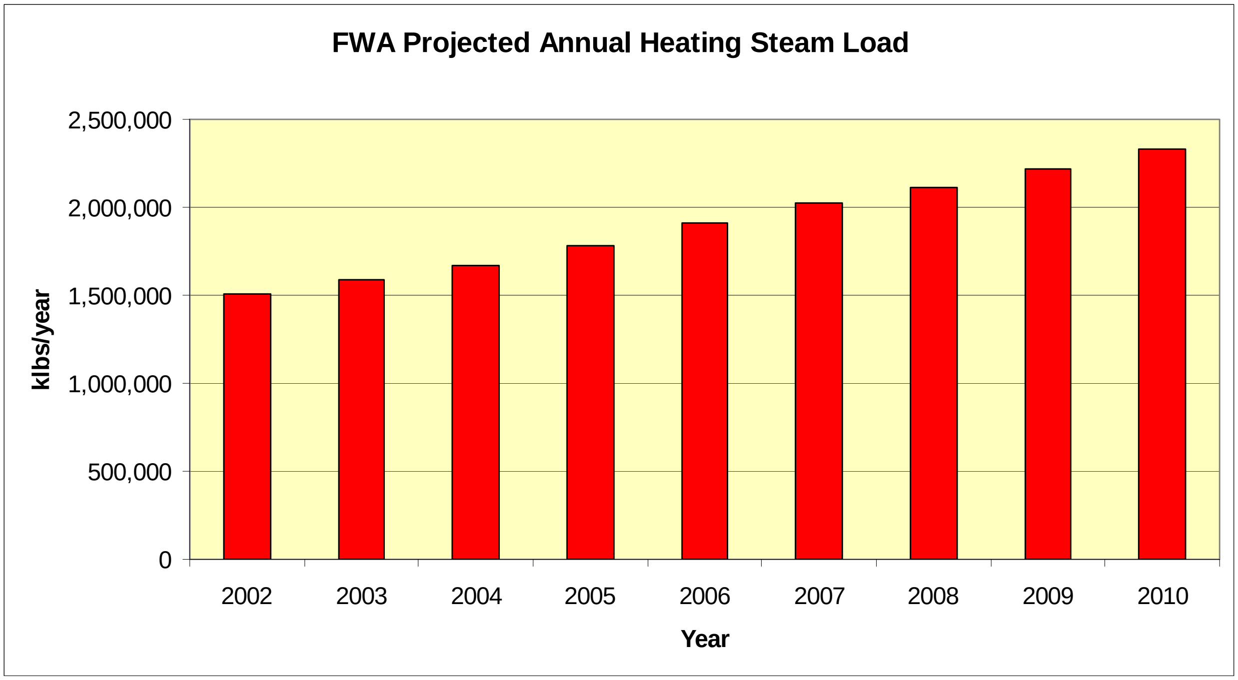

Figure 9. FWA projected annual heating steam load.

6 Project Options

This Project is a continuation of a previous project conducted during the summer of 2002. The scope of that work was to assess the condition of the Fort Wainwright Central Heat and Power Plant, analyze alternatives to the current system, develop recommendations for future project work, and provide feedback to senior Army leadership. That study analyzed the following options:

1. Status Quo (current MCA investment only)
2. Conversion to heating only plant
   a. Coal
   b. Conversion to heating only plant-approved OMA funds, back-up power
3. Heating only plant with oil backup
4. Current CHPP renovation path
5. Standalone CHPP to meet future loads
6. Electricity produced to follow heat load
7. Oil-fired combustion turbines
8. Pressurized fluid bed combustor
9. Circulating fluid bed combustor
10. Heating only satellite plants
11. GVEA electricity/Aurora Energy heating.

Other potential solutions considered included:

- individual boilers at each building
- natural gas technologies
- renewable energy technologies/wind energy.

The recommendation from the report on the previous project was to convert the CHPP to heating only, purchase all electricity from the local electric utility, Golden Valley Electric Association, and to install backup generation on the Installation.

For the purposes of developing a DD1391 to formally request project funding, two alternatives for supplying FWA with the projected requirements for both electricity and heat have been evaluated. Option 1 is the above-listed option 2b, (to convert the existing CHPP to heating only, purchase all required electricity from GVEA and to install backup generation to ensure electric and heating service during a loss of GVEA power). Option 2 is the above-listed option 5, (to expand the existing CHPP so that it can continue to supply a majority of FWA electricity and all heating and to increase the GVEA electric import capacity to ensure electric service during a loss of the CHPP power). While these two options do not provide exactly the same level of service and reliability, they both are designed to meet future load growth and are similar enough to base a valid comparison to determine which option is best for the Installation.

Option 1 Overview

The "Convert FWA CHPP to Central Heating Plant" concept is to:

- convert the existing boilers and associated systems producing 400 PSIG, 725 °F steam to a 100 PSIG, 470 ˚F system
- provide redundant piping between the boiler steam loop and the post extraction header
- provide positive separation between the existing steam system and the turbines
- provide a long-term (15 year) storage system for the existing turbines
- install new substation(s) sized for the future installation electrical load growth
- relocate installation electrical feeders to the new substation
- remove the existing switchgear in the plant.

The "Provide Electrical Backup Generators" concept is to provide and install backup electric generators to cover the critical loads on Fort Wainwright. The generators will include all necessary control systems to allow automatic startup and shutdown, along with local and remote trouble alarm annunciation. The project includes all ancillary systems and new heated structures to allow year round operation. The critical electrical load will be split among multiple generator sets.

Major Components of the project are as follows:

- upgrade controls
- steam conversion through new pressure reducing valves and desuperheaters
- disposition or preservation of existing steam generators
- removal of switchgear
- install new electrical substations
- provide backup generation for critical loads (generators, electrical interface, controls, fuel storage, etc.)
- provide backup generation for CHP (generators, electrical interface, controls, fuel storage, etc.).

The cost to construct this proposed modification to the CHPP is estimated at $78 million. Average annual operating costs are estimated to be $470,000, plus the cost of coal and electricity. This estimate is based on engineering cost build-up from a conceptual design using vendor quotes, MCACES, and PC Cost. The project will result in a reliable system that meets all environmental requirements. The construction is assumed to take 2 years. The data in Table 14 summarize of the cost buildup. Detailed cost development is presented later in this report.

Option 2 Overview

This option consists of upgrading and expanding the CHPP to meet a majority of future electrical load s and all the future heating requirements of the installation. Under this scenario, the CHPP would continue to operate much as it does now. Major Components of the project are:

- upgrade controls
- additional steam turbines
- steam system modifications to support new steam turbines
- upgrade switchgear
- expand size of air-cooled condenser
- overall CHPP upgrades to bring the plant up to current standards
- install new electrical substations
- provide backup generation for CHP (generators, electrical interface, controls, fuel storage, etc.).

The cost of all improvements and modifications is estimated to be $153M. Average annual operating costs are estimated to be $340,800, plus the cost of coal. This estimate is based on the previous study sited above, with some modifications to reflect the same load forecasts, escalation, locality factors, and contingencies as the detailed estimate of Option 1 above. With this option, cost uncertainties in terms of the condition of the existing equipment may lead to unforeseen costs in future years.

Note that, for both options, the existing baghouse project is still required.

Table 14. Cost buildup summary.

Description	Labor	Equipment	Material	Other	Total Cost
Controls	$245,745	$1,533	$239,971	$3,356,539	$3,843,789
PRV's	$9,222,039	$0	$6,318,374	$0	$15,540,412
Mothball Turbines	$99,210	$0	$92,913	$0	$192,124
Remove Swichgear	$566,346	$21,744	$1,082,292	$0	$1,670,384
New Substations	$735,745	$42,628	$7,413,859	$13,733,040	$21,925,274
CHP Backup Generators	$828,788	$26,093	$3,411,750	$0	$4,266,630
Critical Load Back Generators	$3,066,694	$189,068	$24,935,110	$1,762,183	$29,953,056
Sub-Total	**$14,764,566**	**$281,066**	**$43,494,270**	**$18,851,763**	**$77,391,668**

7 Conversion to Heating Only Design Considerations

Several decisions were required to ensure that the conversion to heating only project would ultimately satisfy the requirements and desires of the installation. A project development report was developed and presented to the key stakeholders of the project team. The report presented an overview of each major design requirement and presented options for achieving the requirement. This section presents issues, options, and recommendations for the project design.

Required Control System Modifications

The existing control system is comprised of approximately 7000-8000 points of monitoring and control, which covers both the boiler side and the turbine/generator side. Approximately half of the sensors are dedicated to controlling the steam generation side of the plant and the other half are for the control of the turbine/generator side. The system head end computation and control resides on an Intel 386 class computer with an IBM OS/2 operating system. The OS/2 operating system creates a huge nuisance in retrieving data. It was reported in the field that the operating system does not write to CD writers, only to a floppy disk drive, because drivers were never written for this version of OS/2. This makes data transfer and retrieval very slow. The marginal performance of this system causes a large amount of time to be spent retrieving data, causing delays in other tasks.

Three options for improving the control system performance have been considered: (1) system modification, (2) total replacement, and (3) a system upgrade.

Option 1: System Modification

When the CHPP is converted to heating only, the control system will need to be modified to eliminate the electric generation control. The primary tasks are to remove the existing controls and to modify the software programs for monitoring and control of electric generation. The cost of modifying the existing system is $300,000. This option is the least expensive in terms of installed costs, but is anticipated to be more expensive in the long run due to increased obsolescence (i.e., reduced and more expensive support) and the great amount of time required by CHP personnel to use effectively.

Option 2: Total Replacement

The total replacement path option is to purchase and install a totally new system. The advantage of the new system is that it can be procured through a competitive bidding process thereby controlling the cost of the project. In contrast, the proprietary nature of the existing system limits the choice of vendors who are capable of modifying it. The disadvantage of the total replacement option is that it will require a substantial shutdown of the entire power plant for and extended period of time to switch over equipment and tune the programming.

Option 3: Upgrade to the "Ovation" System

The proposed system upgrade option for this system is to install the Emerson-Westinghouse "Ovation" system. Upgrading to Ovation will require replacing the redundant processor boards in each distributed processing unit (DPU) with ovation processors. Additionally the WESNET cabling needs to be replaced with fast Ethernet cabling, since Ovation communicates on an Ethernet network. With an upgrade to Ovation the distributed control cabinets can be retained with the exception of the processor cards, which have the network interface on them. There is a significant reprogramming effort involved in the conversion. However, a significant portion of the conversion can be handled by a software migration package. This package will construct about 80 percent of the new point data and interface. The remaining 20 percent will require manual reprogramming. The entire switchover has been performed at cogeneration plants larger than the FWA CHPP in a single weekend shutdown.

The advantage of this option is that the Ovation control system is an open protocol and able to communicate with Allen Bradley PLC's as well as with "Ovation." This will help lower the cost of small control projects in the future. A further benefit of Ovation is that the hardware is not software specific.

Recommended Approach

It is recommended to proceed with Option 3, the migration upgrade to the Ovation system. Emerson-Westinghouse Ovation is an accepted standard in the coal-fired electric utility industry. It appears to be highly supported and very powerful, and the open protocol has benefits for future expansion.

Table 15. Total replacement vs. system upgrade configuration.

Control System Comparison	Total New system	Upgrade to "Ovation"
Software	New	New
Network	New	New
HMI Stations	New	New
Engineering Station(s)	New	New
History Station	New	New
DPU		
Processors	New	New
I/O cards	New	Existing
Ease of replacement	Difficult	Difficult
Competitive Bid	Yes	?
Approximate Cost	$10.8 million	$3.85 million

The existing redundant processors in each of the existing DPUs will be replaced with new Ovation processors while the Q rack (the input/output rack) will be retained. The Human Machine Interfaces (HMIs) will be replaced with current vintage workstations. This will include the engineering workstations, the operator work stations, the historian station, and the calculation stations. The current screens and displays will be converted for the new higher resolution displays.

Cost Comparison

Table 15 presents a Total Replacement vs. System Upgrade comparison.

Steam System Modifications

Conversion to 100 psig at 470 °F

Steam produced at 400 psig–650 °F must be reduced to 100 psig–470 °F for the utilidor load, 50 psig for CHP miscellaneous heating, and 10 psig for deareator heating. This will be accomplished by passing the steam through pressure reducing stations and then desuperheaters.

Pressure Reducing Stations

The pressure reducing valves (PRVs) and desuperheaters will be located in the boiler building at the platform level below the mud drum. PRVs will be connected to the common 12-in., 400 psig, header, which connects boilers No. 3, No. 5, and No. 7. Each PRV will be fed by its own 10-in. line coming from a new tap. These lines will parallel the existing lines to the turbines. The 10-in. lines from the desuperheaters will run down to the condenser level and tie into the common 16-in., 100 psig header, which serves the utilidors.

Required Modifications

To produce 400,000 lb/hr. of 100 psig steam will require three operating PRV/desuperheater combinations. Also, 45,000 lb/hr of 10 psig steam will be produced by one station and 40,000 lb/hr of 50 psig steam will be generated in another station. The total estimated installed cost is:

PRV & desuperheater for 100 psig steam 3 PRV & desuperheaters installed	$5,820,000
PRV & desuperheater for 10 psig steam 1 PRV & desuperheater installed	$ 1,940,000
PRV & desuperheater for 50 psig steam 1 PRV & desuperheater installed	$ 1,940,000
Total Cost	**$ 9,700,000**

Optional Modifications Considered

Due to the critical nature of the heating system during the winter, it would be prudent to provide one backup desuperheater at each of the three stations as a means of providing backup in the event of a system failure of one of the new PRV stations. The estimated incremental cost of providing the backup stations is:

PRV & desuperheater for 100 psig steam 1 PRV & desuperheater installed	$ 1,940,000
PRV & desuperheater for 10 psig steam 1 PRV & desuperheater installed	$ 1,940,000
PRV & desuperheater for 50 psig steam 1 PRV & desuperheater installed	$ 1,940,000
Total Additional Cost	**$ 5,820,000**

Recommended Approach

The recommended approach for the conversion of the steam system is to provide one backup desuperheater at each of the three stations as a means of providing backup in the event of a system failure of one of the new PRV stations. Thus the 100 psig steam system would have four PRV stations, the 10 psig system would have two PRV stations and the 50 psig system would have two PRV stations. The total estimated cost for the recommended approach is:

PRV & desuperheater for 100 psig steam 4 PRV & desuperheaters installed	$ 7,760,000
PRV & desuperheater for 10 psig steam 2 PRV & desuperheaters installed	$ 3,880,000
PRV & desuperheater for 50 psig steam 2 PRV & desuperheaters installed	$ 3,880,000
Total Cost	**$ 15,520,000**

(Note: Prices include Alaska factor and is based on intended piping run and location.)

Mothball Steam Turbines

Required Changes to the Steam Turbines

A fundamental change to the CHPP to heating only is the elimination of the electric generation function. One of the design issues is what to do with the steam turbines once they are no longer part of the power plant process.

Options Considered

There are four basic methods of decommissioning to be considered in mothballing the turbine/generator sets (Table 16).

Abandon in Place, No Preservation

At a minimum, the turbines will be disconnected from the steam loop and abandoned in place. This is the least-cost option to pursue. The consequences of this option are that the turbines will not be able to be brought back into service in a timely or cost effective manner. Also, they will remain in the plant until plans for replacement or removal are undertaken.

If the strategy is to use the turbines at future time, one or more of the following options should be considered.

Table 16. Option summary.

	No preservation	Desiccant	Nitrogen	Turning Gear
Materials Deterioration	Rapid	Slow	Slow	N/A
Known state of preservation	N/A	Unknown	Known	Known
Rotor Warp	Highest	Highest	Highest	Lowest
Cost	Lowest	Moderate	High	Highest

Mothball with Desiccant

The turbines are disconnected and sealed with blank off plates. To prevent damage from moisture inside the turbines, desiccant material is placed inside to absorb moisture. This is the lowest cost preservation option, but does not guarantee that the turbine will be preserved for an extended period of time.

Mothball with Nitrogen Blanket

The turbines are disconnected and sealed with blank off plates. To prevent damage from moisture and other decomposing processes inside the turbines, the turbines are pressurized with an inert gas (nitrogen). This option is more expensive than the desiccant approach but is also more effective for long-term preservation. One disadvantage of this approach is that the containment of the nitrogen can be problematic since it can leak from inside the turbine.

Add Turning Gear to Turbines

Turning gears can be installed to slowly rotate the turbine shaft. This is done to prevent the turbine shaft from taking a permanent bow from its own weight as it sits idle. If the shaft should take a bow, the entire shaft and rotor assembly will need to be removed and shipped to a rebuilding shop to be repaired, usually in the lower 48 states.

Recommended Approach

While it is understood that there is a desire to keep the options open for a long-term energy solution at FWA, it is recommended to abandon the existing turbines and forego any preservation activities. Even by standards of the time when this power plant was designed, the turbines operate at very low pressures resulting in inefficient power generation. Industry has been using design pressures of 900 to 1250 psig since the 1930s for steam to drive electric generating turbines. At such low pressure as 400 psig, turbine generators are notably inefficient, compared to higher pressures. Due to the lack of efficiency of these turbines, it is highly unlikely there is any market for the turbines. In addition, due to the inefficiency of these turbines, any likely future electric generation projects for FWA would be based on more state-of-the-art and high efficiency technologies.

Electrical Switchgear

Required Modifications

The existing switchgear dates to the original construction of the current CHPP. It is old technology (not used since the late 1970s) and still contains almost all of the original protective relays, meters and controls. As noted in previous reports, this line-up is intended to be replaced due to its condition. Although the circuit breaker portion of the line-up can continue to function as currently configured, it does need to be updated with new protection relays and controls. If the switchgear were to remain, updating the circuit breakers would be a complicated scheduling task to maintain power to the installation. Working on this switchgear is the equivalent of "open heart surgery" for the installation.

Since most of the line-up serves electrical loads on the installation outside the CHPP, when the new utility substations are installed, these breakers will have no further use. Once the turbines are decommissioned, the breakers serving the turbine/generators will no longer be needed and will be removed.

Options Considered

For the remainder of the switchgear there are two options: (1) upgrade the relays and controls, or (2) replacement of these components. Option 1 will maintain the current 12,470V switchgear as the service for the CHP and will continue the current single-ended circuits to transformers SS-2, SS-3, Ltg-2, and Ltg-3. Under this option the emergency generators will be added to the 12,470 volt switchgear line-up.

Option 2 will eliminate single point failure possibilities that would shut down the entire plant. The best configuration for reliability is to convert the recently installed 4,160-volt switchgear into the service entrance switchgear for the CHP. It has adequate bus capacity to serve the entire CHP load. The service transformers will be increased in size and additional breakers need to be added to the line-up. The additional breakers will feed the four remaining CHP loads that are now served at 12,470 volts and provide a connection point for the new "black start" generators. The existing 12,470 volt and 7,200 volt step-down transformers will be replaced with 4,160 volt primary transformers. Table 17 lists the overall costs of the two options.

Table 17. Switchgear option cost overview.

	Retain 12,470 V Service	Make 4,160 V Service
Basic removal	$56,700	$94,500
Refurbish Breakers	507,000	0
New Breakers	0	609,600
Replacement transformers	0	199,000
Generator voltage adder	10,000	0
Subtotal cost	$573,700	$903,100
Simplified CHP Service	No	Yes
Simplified troubleshooting	No	Yes
Single point failures	Yes	No

Recommended Approach

Option 2, which involves reconfiguring the 4,160-volt switchgear to be the CHP service switchgear, is recommended. Although this is not the lowest cost option, it will greatly simplify the main electrical distribution in the CHP. This will eliminate the possibility of failure of old equipment forcing the CHP offline. This approach also improves electric supply reliability by eliminating the single points of failure, which can cause the plant to shutdown due to feeder failure. The simplified service will also make troubleshooting feeder problems much quicker during a failure. The double-ended systems will allow quicker restoration of power. The elimination of the 12,470 switchgear will eliminate one possible link in the failure chain.

Electrical Substations

Existing Substations

As indicated in section titled, "Electrical" (IN Chapter 4, p 16), the year 2000 electrical requirements for are installation are projected to be 32.5 MW. Once the CHPP is heating only, it is proposed to purchase all electricity from an off-installation provider such as GVEA. The current import capability to FWA from GVEA is 12.5 MW.

The installation needs reliable electrical service under any failure condition. In the existing distribution system this is exemplified by an arrangement that allows remote sections of the distribution circuits to be fed either from their normal breaker at the plant, or from their distant end from another circuit which is fed from another breaker in the plant.

New Substations

The design considerations for the new substations are the primary service voltage, size, and location. GVEA is transitioning from the 69 kV services to 138 kV services to the greatest extent possible. GVEA indicates that their 138 kV service is more reliable and robust than the 69 kV services that FWA is currently using. There is 138 kV service near FWA and GVEA recommends that any new service for FWA be supplied through the 138 kV service. GVEA is also standardizing on a “cookie cutter” substation to allow quicker restoration of service when failures occur in their substations. Figure 10 shows this standard GVEA substation. These are rated 20 MVA nominal and can be fed from either 69 kV or 138 kV. They even have a mobile substation transformer, the longest lead-time item in a substation repair (possibly up to 26 weeks), to allow replacements within 8 hrs from failure of a transformer.

Substation Size

Conveniently, the standard substation size (12/16/20 MVA) matches well to one-half of the total load when fan cooled ratings are used. This size will allow the entire installation to run short term on two substations. An option is to provide a third substation for backup of any one of the two required units. The third substation would also be of value to support the growth of the installation and could help maintain the current practice of having spare distribution capacity for redundancy throughout the installation. Furthermore, the third substation would help support the required distribution system upgrades that will be required for the planned growth.

Figure 10. Standard 20 MVA GVEA substation.

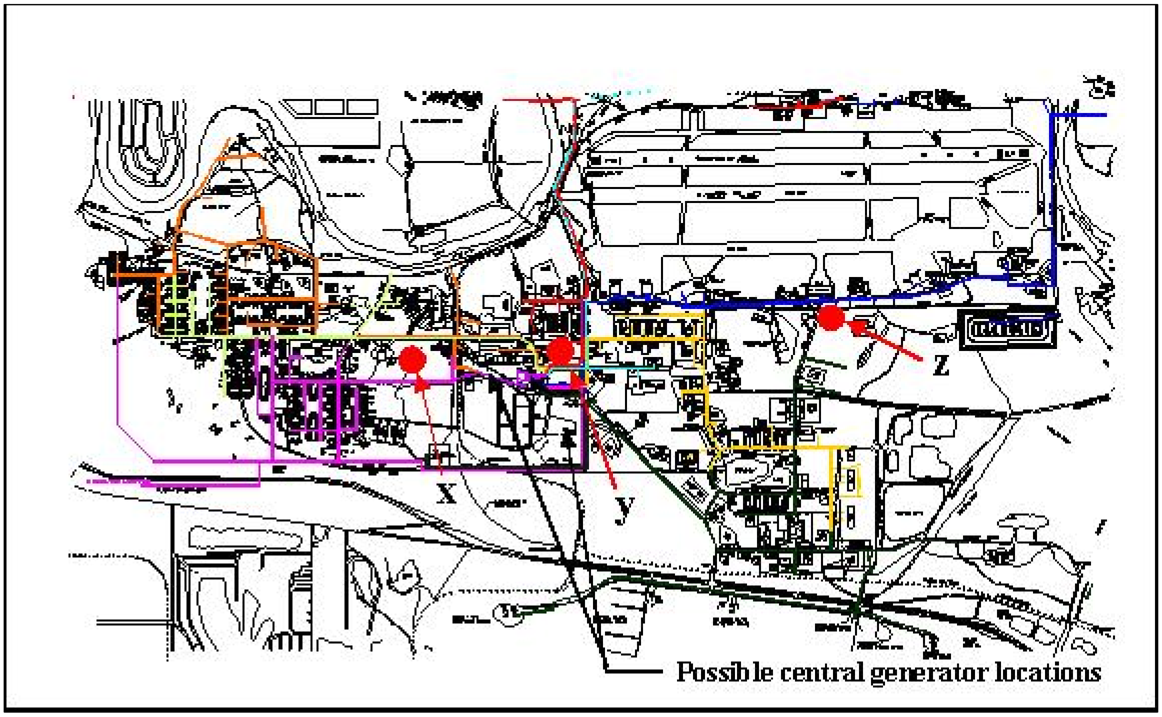

Figure 11. Proposed generator and substation locations.

Substation Location

The substations will be located to take into account the existing FWA distribution infrastructure, force protection issues, and load growth. The existing distribution center for FWA electrical service is the CHPP so one or more substations should be located at or near the CHPP. Force protection issues will require that multiple substations not be co-located, they not be visible from outside the installation, and they have security (fencing, locks, lights, alarms, etc.). The major load growth areas projected for the installation are new family housing, the new hospital, and the SBCT. Figure 11 shows the proposed locations.

Location X is intended to support the proposed growth of residential housing but not to impede the expansion in this area of the installation. Location Z is intended to support the proposed growth that will be concentrated in this area of the installation. Installing the substation at location Z at this time will reduce the future cost for individual facilities' electrical infrastructure in this area since the installed electric capacity will be located closer the new loads.

Option 1—Minimum Requirements

The basic requirement is to provide new substations sufficient to meet the projected peak demand for the entire installation. Due to the remote nature of FWA and the lead-time requirements for substation components, the minimum requirement is to have redundancy for the substation (s) incorporated into the design. The initial option is to provide 100 percent redundancy with two transformers. The estimated cost for this option is $13,500,000.

Option 2—Base Design on GVEA Standard

The second option is to base the design on the GVEA standard 20 MVA substation. This size is also an economical choice when comparing redundant capacity purchased. Although it would seem that the substation capacity could be installed over time, the load growth curve shows that the load rises by 2006 to almost the total expected growth. Therefore the substation capacity must be specified into a project at the outset for completion by 2006 (Table 18).

Table 18. Substations capacity specified at project outset.

Number of Substation Transformers	Redundant Capacity Installed for N+1
2	100%
3	50%

Recommended Approach

Option 2 (install three standard substations (rated 12/26/20 MVA based on their air cooled rating) is recommended. This allows two substations (should one fail) to match the expected load growth of 32.5 MW within their fan cooled rating. Use GVEA standard distribution hardware and configuration for reliability and ease of repair following a failure. Supply the substation from the 138 kV circuit, which is the highest reliability. Add primary side breakers to standard substation to protect the integrity of the 138 kV line and allow partial restoration following a failure. Figure 12 shows the recommended configuration.

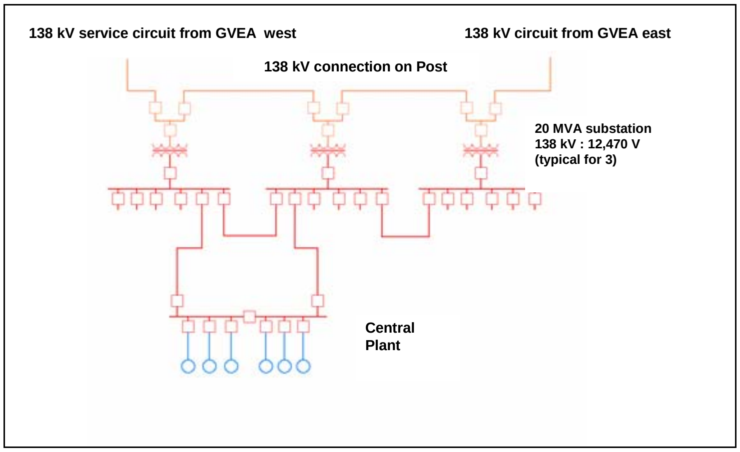

Figure 12. Substation arrangement.

Budgetary Costs

Table 19 lists the costs to implement Option 2 (base design on GVEA standard).

Table 19. Substation budgetary costs.

	Quantity	Per Unit Cost	Extended Cost
Basic substation	3	1,600,000	$ 4,800,000
Additional bay structure	3	600,000	1,800,000
Additional breakers	12	100,000	1,200,000
138 kV breakers	9	200,000	1,800,000
12 kV line rework	7	95,000	665,000
238 kV line work	4.5	600,000	2,700,000
Subtotal substation			$ 12,965,000

Due to the substantial quantity of electricity that FWA will be purchasing from GVEA, GVEA is willing to entertain various financing and maintenance options. The exact options cannot be determined until GVEA conducts its own analysis of projected revenue to determine if they can cover some of the cost for the substations (Table 19) through their existing rate structure, and if they can prorate the additional costs over an extended time frame and add the cost to FWA's monthly invoices.

An analysis was conducted to determine the electric rate that FWA should select when 100 percent of the electric supply is purchased from GVEA. Table 20 lists the rate options. These rates were modeled based on the project electric loads of FWA and compared to determine the most economically favorable option (Figure 13 shows the results).

The data shows that the projected costs are nearly the same for both the GS-2(2) 12,470 volt service and GS-2(3) 138 kV service. Under the rate GS-2(2), the installation is metered on the low voltage side of the meter and GVEA owns and maintains the substation.

Table 20. GVEA rate options.

Rate Schedules	Current Rates	Effective Rates (Includes Fuel Credit)
GS-2 (1) Services 50 kW and higher of demand per Billing Cycle		
Customer Charge*	$50	
Demand Charge**	$7/kW	
Energy Charge*** 0 – 15,000 kWh Over 15,000 kWh	 8.152 ¢/kWh 6.401 ¢/kWh	 7.482 ¢/kWh 5.731 ¢/kWh
GS-2 (2)		

Rate Schedules	Current Rates	Effective Rates (Includes Fuel Credit)
Services at Primary Voltage (up to 12,470 volts)		
Customer Charge	$100	
Demand Charge	$8/kW	
Energy Charge 0 – 15,000 kWh Over 15,000 kWh	 6.667 ¢/kWh 5.837 ¢/kWh	 5.997 ¢/kWh 5.167¢/kWh
GS-2 (3) Services at Transmission Voltage (up to 138 kV)		
Customer Charge	$180	
Demand Charge	$11.25/kW	
Energy Charge (All Energy)	5.197 ¢/kWh	4.527 ¢/kWh

* Customer Charge = Fixed charge ($) that appears monthly on billing statement and is designed to help defray some of the fixed costs involved in providing electric service. These costs include power plant facilities, poles and transformers, vehicles, labor, office equipment and office space.

** Demand Charge = Charge based on maximum rate of delivery of electricity during a billing period, measured in kilowatts (kW). Demand rate is the maximum average power taken for any xx minute interval in the billing period.

*** Energy Charge + Charge (¢/kWh) for the amount of energy used during the billing cycle.

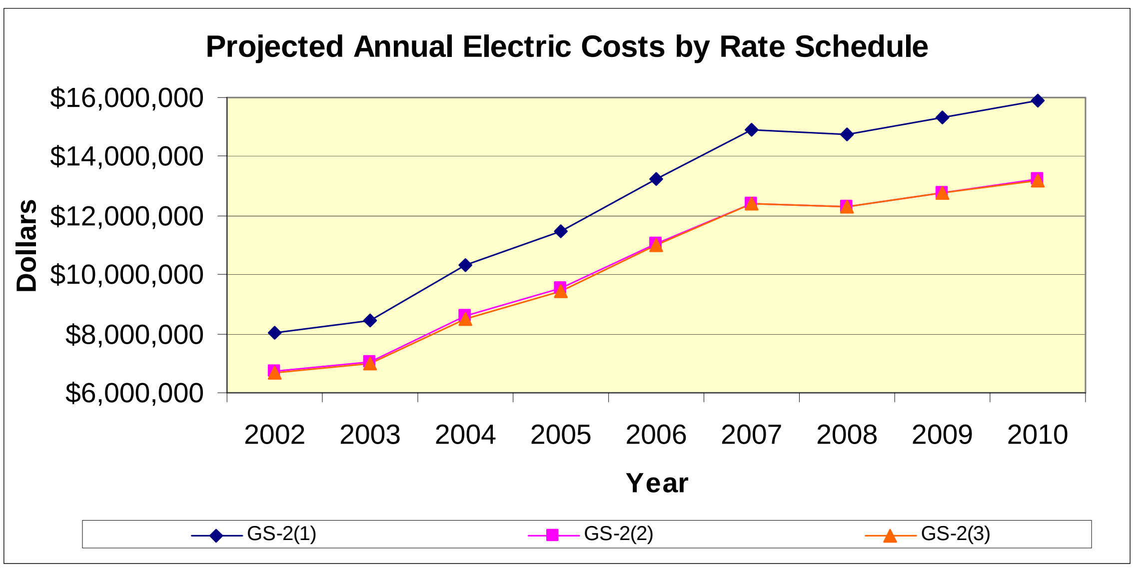

Figure 13. Projected annual electric costs by rate schedule.

Explanation of Approach

Since the main installation Switchgear will be removed, two specific functions need to be replaced. The existing switchgear provides power to the installation external to the CHPP and also powers systems internal to the CHPP. Replacement of the switchgear for the installation loads external to the CHPP will be provided in the electrical substations which will be located remote from the CHPP, closer to the load locations. The replacement of these breakers will simply replace the existing breakers at their current capacity. This will eliminate any major rework of the circuits. The installation circuit size does not maximize the capability of the breakers, but is adequate for current use and will be retained. The CHP will be fed with two circuits, one from each of the two closest substations. The substation breakers will be provided with SCADA monitoring to allow quick restoration of service, especially during the cold winter months.

Heat Plant Backup Electrical Generation

Minimum Requirements

Currently the CHPP does not have a "black start" capability. Either the plant must be able to generate a minimum amount of electricity or GVEA power must be available to start the plant equipment. If neither is available the plant can not be started.

Table 21. Generator sizing per plant loads.

Load	KVA
Boilers & turbines running 12 Oct 2002 (3)	1,296
Misc. plant load	1,037
New ID fans (3)	895
Remaining boiler	730
Start 1 additional boiler	730
Turbines load to decommission	(512)
Total expected plant load	4,176

To provide an adequate level of safety during power failures/outages and allow an orderly start up, emergency generator power is required. If the plant is lost on a power failure and unable to restart in approximately 20 minutes in the midst of winter, some of the utilidors could freeze before they could be reheated. The power source must be automatically started and available in 15 to 30 seconds, to prevent major reheating efforts in the installation heating distribution system. This level of start is only available through the use of reciprocating engine driven generators. The fuel of choice at FWA will be Arctic Diesel oil. The sizing of the generator is based on the plant loads listed in Table 21.

To run the above loads, three (3), 1500 kW generators will be required. To provide the same level of Force Protection as the CHP, the new CHP generator will be located in a building adjacent to the CHP. This location is internal to the installation with no sight lines from outside the installation.

Running three generator sets will consume approximately 324 gal of fuel per hour. Seven days of fuel storage on site represents 55,000 gal of diesel fuel. Fuel will be stored in two, 25,000-gal storage tanks, located in a spill retention dike. Each set should be tested at least once a month and observed by a mechanic. This represents approximately 1 work-day per month. The sets can be run more frequently through a SCADA to improve reliability. Testing every 2 weeks would consume approximately 2,000 gal of fuel oil per month. The estimated cost for this option is $3,200,000.

Options Considered

In keeping with the philosophy of incorporating an N+1 design which allows for an additional unit to be on standby in the event of failure of one of the primary units. The option evaluated is to provide one additional 1,500 kW generator for increased reliability. The estimated incremental cost for this option is $1,100,000 and would bring the total cost of the CHP backup to $4,300,000.

Table 22. Existing backup generator capacity.

Building	Description	Backup Generator Capacity	Fuel Tank (Gallons)
3565	Water Treatment	25 kW	500
1060	Communications	270 kW	1000
1193	Power Plant Building	20 kW	500
1555	Post Headquarters	250 kW	1000
1563	Plant/Utilities Building	190 kW	1000
1580	Flight Control Tower	130 kW	2500
3028	MP Station	25 kW	500
3407	Brigade HQ Building	60 kW	1000
4065	Medical Center/Hospital	2@425 kW & 1@200 kW	12,000

Recommended Approach

The recommendation is to proceed with the N+1 strategy and to install four 1,500 kW generators in a new building located adjacent to the CHP. Install above-ground fuel storage tanks with a combined capacity of 55,000 gal of diesel fuel. This provides the highest level of reliability for CHP backup generation.

Installation Critical Electrical Loads

Existing Backup Generators

The installation has a limited number of existing backup diesel generators that service a number of critical loads at various facilities. Table 22 lists the inventory of the existing backup generators.

Heating System

The buildings on the installation are heated by steam supplied from the CHPP. This steam is distributed through the utilidors to mechanical rooms where the heat from the steam is transferred to glycol liquid to circulate through the building systems. Once the heat is transferred from the steam, the condensate must be returned to the CHPP for efficient operation. The transfer equipment and the condensate return pumps are electrically driven. Without electric power there will be no heat transfer and the buildings will begin to cool down and soon freeze. If steam flow has stopped, the steam lines will cool down and then require heating back up. This is a manual operation, which requires bleeding steam from the end of each line. If the steam is not bled out while the line is heated up, condensate will collect and the line will become waterlogged. Once waterlogged with condensate, steam line explosions can occur. Explosions of this type pose a serious risk to equipment and personnel.

The basic design approach for this project is to keep the central heating plant operating as the heating source for the installation. However, due to the mechanical design of extracting the heat from the utilidors and distributing the heat into the buildings, electricity must be provided to operate the pumps, fans, and controls at each building.

Critical Equipment

Table 23 includes a summary list of critical equipment. In addition to existing backup generators and heating equipment, the table includes sewer lift stations that are required to operate at all times.

Table 23. Lift station summary.

Description	Load	kW
New housing heating pumps	3 locations, w/ (1) 15 HP glycol pump & (1) 1.5 HP condensate pump	55.8
Old housing heating pumps	179 locations, w/ (1) 1.5 HP glycol pump, (1) 1.5 HP condensate pump, & 9 1.7 A zone pumps	1063.3
Large bldg. heating system	21 locations, w/ (1) 25 HP glycol pump, (1) 2 HP condensate pump, & (4) 25 HP air handlers	2891.7
Barracks & small bldg. Heating pumps	160 locations, w/ (1) 5 HP glycol pump & (1) 2 HP condensate pump	1393.9
Sewage lift pumps		
Bldg. #1002	Assume (2) 7.5 HP	11.2
Bldg. #1026	(2) 3 HP	4.5
Bldg. #1045	(2) 2 HP	3.0
Bldg. #1047	(2) 2 HP	3.0
Bldg. #1049	(2) 2 HP	3.0
Bldg. #1051	(2) 7.5 HP	11.2
Bldg. #1056	(2) 5 HP, (2) 2 HP, (1) 1 HP	12.0
Bldg. #1555	(2) 3 HP	4.5
Bldg. #1557	(2) 2 HP	3.0
Bldg. #1562	(2) 3 HP	4.5
Bldg. #3403	(1) 2 HP, (1) 1/2 HP, (2) 7.5 HP	13.1
Bldg. #3724	(2) 3 HP, (1) 10 HP, (1) ¾ HP	12.6
Bldg. #4162	(2) 3 HP, (1) 1/2 HP, (1) 7.5 HP	10.5
N. Post Tie-line	(2) 15 HP	22.5
N. Luzon Station	(2) 5 HP	7.5
S. Luzon Station	(2) 5 HP	7.5

Critical Buildings

FWA has provided a list of the facilities that have been identified as mission critical facilities and must be fully functional at all times to support the needs and requirements of the installation (Table 24).

Load Shedding and Load Shaving

Automatic load shedding is one method of saving the installation energy costs. Load shedding is managing and controlling the loads on the installation. It involves either shutting off equipment, lights, and/or heat, or it involves changing the operating conditions of the lights and/or heat. An example of load shedding is shutting off lights during peak demands, or shutting off an electric heater for a period of time. An example of changing operating parameters is a night setback thermostat. Unlike a night setback thermostat, load shedding is usually needed when the users are the busiest in normal course of operations.

Table 24. Mission critical facilities.

Description	Load	kW
Fire Dept #1054	9387 sq. ft. @ 5 w/sq. ft.	46.9
Fire Dept. #3004	7939 sq. ft. @ 5 w/sq. ft.	38.2
Fire Dept. #4380	3731 sq. ft. @ 5 w/sq. ft.	18.7
Post HQ #1555	91,460 sq. ft. @ 5 w/sq. ft.	457.3
BLM HQ #1541	42,170 sq. ft. @ 5 w/sq. ft.	210.9
MP Station #3028	5770 sq. ft. @ 5 w/sq. ft.	28.9
Control Tower #1580	3872 sq. ft. @ 20 w/sq. ft.	77.4
Communication #1060	16,879 sq. ft. @ 20 w/sq. ft.	337.6
Communication #1070	4000 sq. ft. @ 20 w/sq. ft.	337.6
Dining Facility #1004	12,997 sq. ft. @ 10 w/sq. ft.	130.0
Dining Facility #3416	15,121 sq. ft. @ 10 w/sq. ft.	151.2
Dining Facility #3728	15,121 sq. ft. @ 10 w/sq. ft.	151.2
Dining Facility #3451	Assumed 15,121 sq. ft. @ 10 w/sq. ft.	151.2
Medical Clinic #3406	25,222 sq. ft. @ 15 w/sq. ft.	378.3
Old Hospital #4065	Assume deleted	0
New Bates Hospital	Assume self sufficient	0
Water Treatment #3565	13,398 sq. ft. @ 15 w/sq. ft.	301.0
CHPP #3595	Assume self sufficient	0
Fueling #2078	285 sq. ft. @ 10 w/sq. ft.	2.9
Fueling #3484	411 sq. ft. @ 10 w/sq. ft..	4.1
Commissary #3703	94,676 sq. ft. @ 6 w/sq. ft.	568.0
Hanger #6	47,985 sq. ft. @ 5 w/sq. ft.	239.9
DPW #3022 west	7164 sq. ft. @ 5 w/sq. ft.	35.8
DPW #3022 east	7164 sq. ft. @ 5 w/sq. ft.	35.8
Child Development Center #4024	19,677 sq. ft. @ 6 w/sq. ft.	118.1

Another method of control, which is often mistaken for load shedding, is “load shaving.” Load shaving represents spending energy dollars on an alternate form of energy to save dollars on the energy resource of interest. This is done when electricity costs are the highest and the cost savings are greater than the cost of fuel and operation to generate electricity. Encorp at Fort Bragg did exactly this. The installation will still use the same amount of electrical energy, the difference is that the electricity comes from generators on-site, instead of from the utility. The electric energy still needs to be produced. This process does produce air emissions at the installation. These emissions must be managed as well as the cost of the energy that is burned in the generators. Another aspect of this operation is that the air quality issues may not be a direct trade off, due to the different emissions conditions.

Options Considered

For purposes of analysis and to assure the best plan is in place for Fort Wainwright the critical load back up is provided as three options. Option 1 is total installation back up. Options 2 and 3 are backup for critical loads only. Both Options 1 and 3 use centralized generators. Option 2 uses distributed generators. Distributed generators will be located near each building on the installation, while the centralized generation options will be located in the vicinity of the current CHPP. The data in Table 25 summarizes the three options.

"Critical only" capacity refers to planning for the critical building list, plus those pieces of equipment needed for heating the buildings. The standby power for the CHP will be located at the CHP as described in the Heat Plant Backup Electrical Generation Section (p 44).

Table 25. Critical power generation options.

	Option 1: Central Generators for Total Post Backup	**Option 2: Distributed Generators for Critical loads only**	**Option 3: Central Generators for Critical loads only**
Number of sets	4+1	201	2 + 1
Fuel storage tanks	12	201	10
Work-hours needed per month to test each set once monthly	14	603	8
FTE for testing	0.08	3.5	0.05
Locations to secure	1	201	1
Budget cost	$ 30,000,000	$ 34,000 000	$ 33,000,000
Controls FTE	0.1	1	1

Generators for standby will start within 5-10 minutes and are not intended for life support and extremely critical functions, such as emergency communication, hospital patients, police, and fire safety response.

All generators will be located internal to the installation or shielded from line of sight of those outside the installation fence. All generators will be housed in buildings for both force protection and weather protection.

Option 1— Total Installation Backup

This option provides standby generation on site, with a total capacity equal to the installation's projected electrical demands in the year 2010, less the power required for backing up the CHPP auxiliaries. Although this involves the most generation capacity, it is the simplest system to construct and maintain. At one central point, sufficient generation will be provided to power the entire installation, should the utility service fail. This option includes combustion turbines summer rated at 6.5 MW each and winter rated at 7.8 MW each.* Four will be needed to meet the base load (less the CHP auxiliary load) and one will be needed to allow maintenance and repair. The combustion turbine facility will also include two small diesel generator sets that will provide the start up power to the combustion turbines. The combustion turbines can also be run in parallel with the utility, in an effort to peak shave or provide the utility support. Fuel oil will be provided from a single aboveground oil storage tank, located inside a retention basin and berm with fence.

> ***Option 1 Equipment Requirement:*** Five (5) 6.5 MW combustion turbines, 450,000-gal fuel oil storage, 7700 sq ft building, Overhead electrical connections, and a SCADA system.
>
> Total Estimated Cost: $30,000,000

The advantages to this approach are that it is the least complex of the options evaluated, the work-hours required for monthly testing are the lowest, and fueling logistics are straightforward for a centralized storage facility. For reliability, this option provides an N+1 backup strategy for the critical loads. Finally, in the event of a loss of power to the installation, all installation activities will be supplied with electricity so that normal mission activities can proceed in an unrestrained manner.

The disadvantages of this approach are total installed capacity of backup generation equal to the entire installation electric load (less the CHP load), the required fuel storage is the largest of the options evaluated and the centralized approach may be less desirable from a Force Protection point of view.

Option 2— Backup for Critical Loads Only (Distributed Generation)

Under this option, diesel engine distributed generators located near each remote critical load are used to provide back up power. The electrical service or distribution system in the building will be modified to add an automatic transfer switch. All generator locations will be centrally monitored and may be remotely run. This will reduce the manpower required for routine operations while still maintaining excellent reliability.

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* Combustion turbine performance is strongly influenced by ambient conditions. The higher the temperature, the less dense the intake air to the turbines, and the less power generated or efficiency.

The advantage to this approach is that the total installed capacity of backup generation is lower than the total electric requirement for the entire installation. In addition, a failure of one generator does not result in a loss of electrical supply to a large portion of the installation. Finally, this approach could potentially provide backup for facilities when there is a failure on one of the installation electrical distribution lines.

The disadvantages of this approach are that it is the most complex of the options evaluated, the work-hours required for monthly testing is high, siting issues for each generator need to be addressed and fueling logistics for 201 fuel storage tanks could prove to be a problem. In addition, this option does not provide for an N+1 backup strategy for any building or critical equipment.

Option 2 Equipment Requirement: (162) 30 kW generators, (5) 50 kW generators, (26) 150 kW generators, (3) 250 kW generators, and (5) 500 kW diesel generator sets, (193) 170 sq ft buildings and (8) 250 sq ft buildings, automatic transfer switch installation, base mounted oil storage, and a SCADA system.

Total Estimated Cost: $34,000,000

Option 3— Backup for Critical Loads Only (Centralized Generation)

Under this option, centrally located standby power is installed to meet critical loads only. This option involves locating combustion turbines in a central location and distributing the power through the normal distribution system. Since only enough generator capacity will be provided to supply the critical loads, each building will need to be modified so that all noncritical loads will be shed in a power failure. Likewise, each building will need to be arranged for remote restoration of power when utility service returns. Although this is the most complex option, it provides the best availability of load control and monitoring for the installation. Using this SCADA equipment, the central dispatch location can be instantly notified of power failures on the installation. Also, if load curtailment should be desirable either for utility cost control or as a necessity to keep the utility on line, the installation will be able to remotely control its electrical loads. Additionally, although with less reduction potential than in option 1, the installation can peak shave using the combustion turbine generators in an effort to control utility load or for economic reasons.

Option 3 Equipment Requirement: Three (3) 6.5 MW combustion turbines, 180,000-gal fuel oil storage, 4,000 sq ft building, Overhead line connections, a SCADA system, controls at 197 residential and small buildings, 30 medium buildings, and 20 large buildings.

Total Estimated Cost: $33,000,000

Recommendation

Option 1 is recommended. The critical power loads should be supplied from centrally located standby generators sized to meet the entire projected electrical load of the installation. This is the least costly and most flexible solution.

8 Cost Estimate Details

The tables in this chapter list detailed cost estimates for conversion to the "heating-only" option:

Table 26	for the entire project	Tables 33 and 34	for critical load backup generators.
Table 27	for controls	Table 35	for IC engine fuel costs.
Table 28	for steam conversion	Table 36	for engine maintenance
Table 29	to mothball turbines	Table 37	annual maintenance
Table 30	for switchgear	Table 38	for the control system
Table31	for substations	Table 39	for annual security
Table 32	for CHP backup generators	Table 40	for electricity and coal (annual)

Construction Costs

The total cost estimate was developed through a detailed conceptual design and applying costs from either MCACES, PCCOST database values, and price quotes. All the raw values are based on the cost that is appropriate for the continental United States. These values are then scaled to account for the location factor (2.01), contingency (12 percent) and Supervision, Inspection and Overhead (6.5 percent). The cost development details are presented in the following sections

Table 26. Project cost estimate.

Description	Labor	Equipment	Material	Other	Total Cost
Controls	$245,745	$1,533	$239,971	$3,356,539	$3,843,789
PRV's	$9,222,039	$0	$6,318,374	$0	$15,540,412
Mothball Turbines	$99,210	$0	$92,913	$0	$192,124
Remove Switchgear	$566,346	$21,744	$1,082,292	$0	$1,670,384
New Substations	$735,745	$42,628	$7,413,859	$13,733,040	$21,925,274
CHP Backup Generators	$828,788	$26,093	$3,411,750	$0	$4,266,630
Critical Load Back Generators	$3,066,694	$189,068	$24,935,110	$1,762,183	$29,953,056
Sub-Total	**$14,764,566**	**$281,066**	**$43,494,270**	**$18,851,763**	**$77,391,668**

Controls

Table 27. Control cost details.

Description	Quantity	Units	Labor	Equipment	Material	Other	Unit Cost	Total Cost	Source
Factory Upgrade Package	1	LS	$0.00	$0.00	$0.00	$1,400,000.00	$1,400,000.00	$1,400,000.00	USR
Telephone cable, #22 AWG, on poles, 4 pair	14.5	MLF	$5,739.25	$639.60	$3,175.50	$0.00	$658.92	$9,554.00	MIL
Factory Engineer Field programming	1	LS	$6,400.00	$0.00	$0.00	$0.00	$6,400.00	$6,400.00	USR
Remove and replace proc units	16	EA	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	USR
Remove and replace HMI units	6	EA	$7,200.00	$0.00	$72,000.00	$0.00	$13,200.00	$79,200.00	USR
Conversion start-up	1	LS	$83,160.00	$0.00	$19,250.00	$0.00	$102,410.00	$102,410.00	USR
MCACES Sub-Total			**$102,499.25**	**$639.60**	**$100,091.03**	**$1,400,000.00**	**$1,603,229.87**	**$1,603,230.00**	
Locality Factor	2.01		$206,023.49	$1,285.60	$201,182.97	$2,814,000.00	$3,222,492.04	$3,222,492.30	
Contingency	12%		$24,722.82	$154.27	$24,141.96	$337,680.00	$386,699.04	$386,699.08	
SIO	6.50%		$14,998.51	$93.59	$14,646.12	$204,859.20	$234,597.42	$234,597.44	
Grand Total			***$245,744.82***	***$1,533.46***	***$239,971.05***	***$3,356,539.20***	***$3,843,788.50***	***$3,843,788.82***	

Steam Conversion

Table 28. Steam conversion cost details.

Description	Quantity	Units	Labor	Equipment	Material	Other	Unit Cost	Total Cost	Source
10" Tie to main steam header	8	EA	$120,000.00	$0.00	$16,000.00	$0.00	$17,000.00	$136,000.00	USR
10" gate valve, 600#	24	EA	$51,456.00	$0.00	$315,912.00	$0.00	$15,307.00	$367,368.00	USR
8" globe valve, 600#	8	EA	$15,088.00	$0.00	$98,472.00	$0.00	$14,195.00	$113,560.00	USR
1" gate valve, 800# drain	16	EA	$2,784.00	$0.00	$3,040.00	$0.00	$364.00	$5,824.00	USR
10" schedule 80, grade A, including 3 1/2" insulation, Al	600	FT	$94,506.00	$0.00	$72,600.00	$0.00	$278.51	$167,106.00	USR
10" ell, schedule 80, grade A	48	EA	$26,880.00	$0.00	$15,200.16	$0.00	$876.67	$42,080.00	USR
10" tee, schedule 80, grade A	32	EA	$27,648.00	$0.00	$15,360.00	$0.00	$1,344.00	$43,008.00	USR
8" PRV & piolets	8	EA	$26,400.00	$0.00	$208,000.00	$0.00	$29,300.00	$234,400.00	USR
16" gate valve, 300 #	16	EA	$70,560.00	$0.00	$280,480.00	$0.00	$21,940.00	$351,040.00	USR
16" schedule 40, grade, 200	1,600.00	LF	$369,600.00	$0.00	$152,000.00	$0.00	$326.00	$521,600.00	USR
16" schedule 40, grade A, ell	96	EA	$133,056.00	$0.00	$82,080.00	$0.00	$2,241.00	$215,136.00	USR
16" schedule 40, grade A, tee	32	EA	$48,576.00	$0.00	$30,880.00	$0.00	$2,483.00	$79,456.00	USR
Desuperheater spray nozzle	8	EA	$17,152.00	$0.00	$120,000.00	$0.00	$17,144.00	$137,152.00	USR
1" control valve for Desuperheater	8	EA	$17,152.00	$0.00	$80,000.00	$0.00	$12,144.00	$97,152.00	USR
16" tie-in in turbine room	8	EA	$200,000.00	$0.00	$0.00	$0.00	$25,000.00	$200,000.00	USR
1" gate valve, 800# (drain)	48	EA	$4,176.00	$0.00	$4,560.00	$0.00	$182.00	$8,736.00	USR
structural support steel	8	LS	$121,944.00	$0.00	$149,304.00	$0.00	$33,906.00	$271,248.00	USR
seismic hangers	8	LS	$1,200,000.00	$0.00	$80,000.00	$0.00	$160,000.00	$1,280,000.00	USR
tie-in to feedwater header	8	LS	$24,000.00	$0.00	$4,000.00	$0.00	$3,500.00	$28,000.00	USR
1 1/2", sch 80, grade A	1,200.00	LF	$37,392.00	$0.00	$11,592.00	$0.00	$40.82	$48,984.00	USR
1 1/2", 3000#, socket weld ell	80	LF	$6,512.00	$0.00	$2,288.00	$0.00	$110.00	$8,800.00	USR
1 1/2", 800#, gate valve	32	EA	$3,792.00	$0.00	$6,336.00	$0.00	$316.50	$10,128.00	USR
1/2", 800#, gate valve	32	EA	$2,784.00	$0.00	$3,040.00	$0.00	$182.00	$5,824.00	USR
seismic hangers	8	LS	$160,000.00	$0.00	$80,000.00	$0.00	$30,000.00	$240,000.00	USR
safety valve, 6" x 8" set @ 150psig	8	LS	$52,800.00	$0.00	$116,016.00	$0.00	$21,102.00	$168,816.00	USR
10" vent pipe	400	LF	$63,000.00	$0.00	$48,400.00	$0.00	$278.50	$111,400.00	USR
10" vent pipe	400	LF	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	USR
12" combined vent pipe	720	LF	$163,296.00	$0.00	$125,438.40	$0.00	$401.02	$288,734.00	USR
roof opening	8	LS	$40,000.00	$0.00	$24,000.00	$0.00	$8,000.00	$64,000.00	USR
seismic hangers	8	LS	$160,000.00	$0.00	$80,000.00	$0.00	$30,000.00	$240,000.00	USR
steam traps	40	EA	$104,000.00	$0.00	$0.00	$0.00	$2,600.00	$104,000.00	USR
control, loop controller	16	EA	$12,000.00	$0.00	$40,000.00	$0.00	$3,250.00	$52,000.00	USR
c, start-upontrol, loop controller	16	EA	$16,000.00	$0.00	$0.00	$0.00	$1,000.00	$16,000.00	USR
control, pressure transmitter	8	EA	$6,000.00	$0.00	$20,000.00	$0.00	$3,250.00	$26,000.00	USR
control, pressure transmitter, start-up	8	EA	$6,000.00	$0.00	$0.00	$0.00	$750.00	$6,000.00	USR
control, temperature transmitter	24	EA	$5,400.00	$0.00	$13,200.00	$0.00	$775.00	$18,600.00	USR
control, temperature transmitter, start-up	24	EA	$5,124.00	$0.00	$0.00	$0.00	$213.50	$5,124.00	USR
control, thermo well	24	EA	$5,400.00	$0.00	$2,400.00	$0.00	$325.00	$7,800.00	USR
control, orifice plate	16	EA	$70,200.00	$0.00	$40,000.00	$0.00	$6,887.50	$110,200.00	USR
control, orifice plate, 1 1/2"	8	EA	$3,300.00	$0.00	$9,600.00	$0.00	$1,612.50	$12,900.00	USR
control, flow transmitter	24	EA	$76,500.00	$0.00	$60,000.00	$0.00	$5,687.50	$136,500.00	USR
control, flow transmitter, start-up	24	EA	$24,000.00	$0.00	$0.00	$0.00	$1,000.00	$24,000.00	USR
control, flow recorder	8	EA	$12,000.00	$0.00	$24,000.00	$0.00	$4,500.00	$36,000.00	USR
control, cabinet	8	EA	$12,000.00	$0.00	$24,000.00	$0.00	$4,500.00	$36,000.00	USR
control, Westinghouse interface	8	LS	$60,000.00	$0.00	$16,000.00	$0.00	$9,500.00	$76,000.00	USR
control, Westinghouse interface, start-up	8	LS	$20,000.00	$0.00	$0.00	$0.00	$2,500.00	$20,000.00	USR
control, Westinghouse programming	8	LS	$48,000.00	$0.00	$12,000.00	$0.00	$7,500.00	$60,000.00	USR
control, Westinghouse programming, start-up	8	LS	$100,000.00	$0.00	$0.00	$0.00	$12,500.00	$100,000.00	USR
MCASES Sub-Total			**$3,846,478.00**	**$0.00**	**$2,635,370.47**	**$0.00**	**$6,481,848.47**	**$6,481,848.00**	
Locality Factor	2.01		$7,731,420.78	$0.00	$5,297,094.64	$0.00	$13,028,515.42	$13,028,514.48	
Contingency	12%		$927,770.49	$0.00	$635,651.36	$0.00	$1,563,421.85	$1,563,421.74	
SIO	6.50%		$562,847.43	$0.00	$385,628.49	$0.00	$948,475.92	$948,475.85	
Grand Total			***$9,222,038.71***	***$0.00***	***$6,318,374.49***	***$0.00***	***$15,540,413.20***	***$15,540,412.07***	

Mothball Turbines

Table 29. Mothball turbine cost detail.

Description	Quantity	Units	Labor	Equipment	Material	Other	Unit Cost	Total Cost	Source
split piping at flange and install blind flange	20	EA	$16,380.00	$0.00	$24,560.00	$0.00	$2,047.00	$40,940.00	USR
Remove control points from programming	1	LS	$25,000.00	$0.00	$12,000.00	$0.00	$37,000.00	$37,000.00	USR
MCASES Sub-Total			**$41,380.00**	**$0.00**	**$38,753.60**	**$0.00**	**$80,133.60**	**$80,134.00**	
Locality Factor	2.01		$83,173.80	$0.00	$77,894.74	$0.00	$161,068.54	$161,069.34	
Contingency	12%		$9,980.86	$0.00	$9,347.37	$0.00	$19,328.22	$19,328.32	
SIO	6.50%		$6,055.05	$0.00	$5,670.74	$0.00	$11,725.79	$11,725.85	
Grand Total			***$99,209.71***	***$0.00***	***$92,912.84***	***$0.00***	***$192,122.55***	***$192,123.51***	

Switchgear

Table 30. Switchgear cost detail.

Description	Quantity	Units	Labor	Equipment	Material	Other	Unit Cost	Total Cost	Source
Primary Facilities									
rem Swyd substa, switchgear, w/air CB, 1200 A, 750 MVA, 13.8	10	EA	$13,349.83	$1,994.72	$10,000.00	$0.00	$2,534.45	$25,345.00	MIL
Swyd substa, vacuum CB, 1200 A, 500 MVA, 13.8 kV	8	EA	$6,051.92	$904.27	$76,912.00	$0.00	$10,483.52	$83,868.00	MIL
Electric Service									
Swyd substa oil xfmr, 14.4 kV, 2 winding, 3 phase, 5000 kVA	2	EA	$4,545.99	$111.63	$110,542.00	$0.00	$57,599.81	$115,200.00	MIL
Swyd substa, vacuum CB, 1200 A, 500 MVA, 13.8 kV	2	EA	$1,512.98	$226.07	$19,228.00	$0.00	$10,483.52	$20,967.00	MIL
Substn,112.5-1500kVA xfmr, 15 kV, 600A,2 posn floor mtd, fused	4	EA	$3,377.19	$504.62	$44,138.00	$0.00	$12,004.95	$48,020.00	MIL
Substn, primary lightning arrestors, accessories, fused LB	4	EA	$0.00	$0.00	$3,838.00	$0.00	$959.50	$3,838.00	MIL
Substn, accessories, key interlock, fused LB sw	4	EA	$0.00	$0.00	$4,376.00	$0.00	$1,094.00	$4,376.00	MIL
Substn, dry xfmr, 150 kVA, 4160 V pri, 208y/120 V secondary	2	EA	$727.36	$17.86	$9,210.00	$0.00	$4,977.61	$9,955.00	MIL
Substn, dry xfmr, 500 kVA, 4160 V pri, 480y/277 V secondary	2	EA	$1,414.31	$34.73	$26,432.00	$0.00	$13,940.52	$27,881.00	MIL
Substn, switchgear 277/480 V, manual, 800 A, w/air circuit	4	EA	$1,620.07	$275.27	$10,650.00	$0.00	$3,136.33	$12,545.00	MIL
Site Improvements and Demolition									
Swyd substa oil xfmr, pad and containment	2	EA	$203,621.08	$5,000.00	$110,542.00	$0.00	$159,581.54	$319,163.00	MIL
MCASES Sub-Total			**$236,220.73**	**$9,069.17**	**$451,420.08**	**$0.00**	**$696,709.96**	**$696,711.00**	
Locality Factor	2.01		$474,803.67	$18,229.03	$907,354.36	$0.00	$1,400,387.02	$1,400,389.11	
Contingency	12%		$56,976.44	$2,187.48	$108,882.52	$0.00	$168,046.44	$168,046.69	
SIO	6.50%		$34,565.71	$1,327.07	$66,055.40	$0.00	$101,948.18	$101,948.33	
Grand Total			***$566,345.81***	***$21,743.59***	***$1,082,292.28***	***$0.00***	***$1,670,381.64***	***$1,670,384.13***	

Substations

Table 31. Substation cost detail.

Description	Quantity	Units	Labor	Equipment	Material	Other	Unit Cost	Total Cost	Source
Primary Facilities									
Swyd substa oil circuit breaker, 138 kV, 3500 MVA	9	EA	$71,899.83	$1,765.53	$764,190.00	$0.00	$93,095.04	$837,855.00	MIL
Swyd substa oil circuit breaker access,adj 3 shot,recloser relay	9	EA	$21,600.00	$0.00	$177,750.00	$0.00	$22,150.00	$199,350.00	MIL
Swyd substa oil circuit breaker access, 1 ph, overcurrent relay	9	EA	$22,500.00	$0.00	$212,400.00	$0.00	$26,100.00	$234,900.00	MIL
Swyd substa oil CB access, 3ph, directional overcurrent relay	30	EA	$3,567.95	$0.00	$99,090.00	$0.00	$3,421.93	$102,658.00	MIL
Swyd substa oil CB access, 3ph, under/over volt, voltage relay	30	EA	$2,862.42	$0.00	$66,840.00	$0.00	$2,323.41	$69,702.00	MIL
Swyd substa oil CB access, differential relay package	9	EA	$3,233.93	$0.00	$32,670.00	$0.00	$3,989.33	$35,904.00	MIL
Swyd substa oil xfmr, 14.4 kV, 2 winding, 3 phase, 12/14/20 kVA	3	EA	$91,629.61	$2,250.00	$605,850.00	$0.00	$233,243.20	$699,730.00	MIL
Swyd substa, switchgear, w/air CB, 1200 A, 500 MVA, 13.8 kV	30	EA	$34,042.07	$5,086.53	$873,600.00	$0.00	$30,424.29	$912,729.00	MIL
Excavate trench, hvy soil, 4'-6' D, 3/4 CY excavator	1,275.00	CY	$1,512.92	$650.12	$0.00	$0.00	$1.70	$2,163.00	CIV
Hauling, off hwy haulers, 26 CY, 1 mile RT @ 20 mph (4.2 cyc/hr)	1,275.00	CY	$349.86	$659.05	$0.00	$0.00	$0.79	$1,009.00	MIL
Placing conc, footings, spread, over 5 CY, direct chute	1,275.00	CY	$13,897.50	$628.96	$0.00	$0.00	$11.39	$14,526.00	MIL
CMU, back-up, 8" x 8" x 16", no scaf/reinf, 2000 psi	900	SF	$2,874.51	$0.00	$1,170.00	$0.00	$4.49	$4,045.00	MIL
CMU, decorative, 8" x 8" x 16", split/scored split, no	2,100.00	SF	$9,094.47	$0.00	$8,505.00	$0.00	$8.38	$17,599.00	MIL
Walls & ceilings, plywood pnl & veneer, brush, one coat, appl	2,100.00	SF	$522.27	$0.00	$0.00	$0.00	$0.25	$522.00	CIV
Ctg & paints, zinc rich epoxy, E-303B, 1 mil	450	SF	$0.00	$0.00	$45.00	$0.00	$0.10	$45.00	CIV
Fence,scty,10' x 10',transom for10' fence,galv,dbl,gate,w/3 barb	1,500.00	EA	$1,335.36	$589.68	$2,766.48	$0.00	$781.92	$4,692.00	MIL
Fence, CL scty, galv,10'H, 2.5"line post@10',3"pull	6	LF	$13,905.00	$6,150.00	$20,850.00	$0.00	$27.27	$40,905.00	MIL
substation structure	6	LF	$0.00	$0.00	$0.00	$3,600,000.00	$600,000.00	$3,600,000.00	USR
substation insulators and hardware	3	LF	$0.00	$0.00	$0.00	$435,000.00	$145,000.00	$435,000.00	USR
Support Facilities									
Electric									
795 ACSR, 138 kv line	4.5	MI	$0.00	$0.00	$0.00	$1,350,000.00	$300,000.00	$1,350,000.00	USR
336 ACSR, 12.47 kv line	7	MI	$0.00	$0.00	$0.00	$343,000.00	$49,000.00	$343,000.00	USR
Information Systems									
Fiber optic sys, aerial/duct, cable, 62.5 microns, outdoor	23,760.00	LF	$11,060.28	$0.00	$44,906.40	$0.00	$2.36	$55,967.00	MIL
Fiber optic sys, transmission, connectors, 62.5 micron cable	12	EA	$233.23	$0.00	$109.56	$0.00	$28.57	$343.00	MIL
Fiber optic sys, receiver, 1.9 mile range	4	EA	$155.48	$0.00	$2,972.00	$0.00	$781.87	$3,127.00	MIL
Fiber optic sys, transmitter, 1.9 mile range	4	EA	$155.48	$0.00	$2,972.00	$0.00	$781.87	$3,127.00	MIL
Fiber optic sys, cable enclosure, interior NEMA 13	4	EA	$444.24	$0.00	$571.20	$0.00	$253.86	$1,015.00	MIL
MCASES Sub-Total			**$306,876.41**	**$17,779.87**	**$3,092,293.10**	**$5,728,000.00**	**$4,221,430.96**	**$9,144,950.00**	
Locality Factor	2.01		$616,821.58	$35,737.54	$6,215,509.13	$11,513,280.00	$8,485,076.23	$18,381,349.50	
Contingency	12%		$74,018.59	$4,288.50	$745,861.10	$1,381,593.60	$1,018,209.15	$2,205,761.94	
SIO	6.50%		$44,904.61	$2,601.69	$452,489.06	$838,166.78	$617,713.55	$1,338,162.24	
Grand Total			***$735,744.79***	***$42,627.74***	***$7,413,859.29***	***$13,733,040.38***	***$10,120,998.93***	***$21,925,273.68***	

CHP Backup Generators

Table 32. CHP backup generators cost detail.

Description	Quantity	Units	Labor	Equipment	Material	Other	Unit Cost	Total Cost	Source
Primary Facilities									
Building									
CMU, decorative, 8" x 8" x 16", split/scored split, no	4,650.00	SF	$20,134.50	$0.00	$18,832.50	$0.00	$8.38	$38,967.00	MIL
Framing, joists, 2" x 4"	2,557.50	BF	$1,713.53	$0.00	$1,508.93	$0.00	$1.26	$3,222.00	RSM
Sheathing, plywood on roof, ext CDX, 3/4" thick	4,650.00	SF	$2,139.00	$0.00	$3,766.50	$0.00	$1.27	$5,906.00	MIL
Wall/ceiling insul,3.5" thk,R11, 15" W, fbgls, foil faced,	4,650.00	SF	$790.50	$0.00	$1,488.00	$0.00	$0.49	$2,279.00	MIL
Wall/ceiling insul, 6" thk, R19, 15" W, fbgls, foil faced,	4,360.00	SF	$915.60	$0.00	$1,744.00	$0.00	$0.61	$2,660.00	MIL
Walls & ceilings, plywood pnl & veneer, spray, one coat, appl	4,360.00	SF	$523.20	$0.00	$0.00	$0.00	$0.12	$523.00	CIV
Ctg & paints, Type I paint, TT-P-615, 600 SF/Gal	4,360.00	SF	$0.00	$0.00	$218.00	$0.00	$0.05	$218.00	CIV
Sheathing, plywood, exterior CDX, 5/8" thick	4,970.40	SF	$2,634.31	$0.00	$3,330.17	$0.00	$1.20	$5,964.00	MIL
Roof truss, 2" x 4",1' overhang,32' span, plate conn,24" OC,4/12	65.4	EA	$1,657.89	$514.04	$4,939.01	$0.00	$108.73	$7,111.00	MIL
Asphalt shingles,210-235 lb/sq, inorganic, class A, std strip	4,970.40	SQ	$246,531.84	$0.00	$127,192.54	$0.00	$75.19	$373,724.00	MIL
Excavate trench, hvy soil, 4'-6' D, 3/4 CY excavator	310	CY	$368.90	$158.10	$0.00	$0.00	$1.70	$527.00	CIV
Backfill, sand bedding trenches, front-end loader, 1.5 CY	232.5	CY	$232.50	$160.43	$3,685.13	$0.00	$17.54	$4,078.00	MIL
Concrete ready mix, regular weight, 3500 psi	77.5	CY	$0.00	$0.00	$4,979.38	$0.00	$64.25	$4,979.00	RSM
Forms in place, footing, spread, plywood, 1 use	620	SF	$2,120.40	$0.00	$1,054.00	$0.00	$5.12	$3,174.00	MIL
CMU, back-up, 12" x 8" x 16", no scaf/reinf, 2000 psi	1,860.00	SF	$7,514.40	$0.00	$3,645.60	$0.00	$6.00	$11,160.00	MIL
Excavating, bulk, dozer, small area, open site, shaping w/small	4,360.00	CY	$3,313.60	$1,656.80	$0.00	$0.00	$1.14	$4,970.00	MIL
Base, prepare & roll sub-base, small areas to 2500 SY	483.96	SY	$246.82	$183.90	$0.00	$0.00	$0.89	$431.00	MIL
Concrete ready mix, regular weight, 3500 psi	87.2	CY	$0.00	$0.00	$5,602.60	$0.00	$64.25	$5,603.00	RSM
Finishing floors, monolithic, float finish	4,360.00	SF	$1,526.00	$0.00	$0.00	$0.00	$0.35	$1,526.00	MIL
Clear & grub, clear site w/335 HP dozer, trees to 12" dia	65.4	EA	$165.46	$289.72	$0.00	$0.00	$6.96	$455.00	AF
Clear & grub, grub & stack, 400 HP dozer	261.6	CY	$75.86	$164.81	$0.00	$0.00	$0.92	$241.00	AF
Generators and Infrastructure									
Generator set, dsl eng, xfr sw&fuel tank,1500 kW, incl btry,	4	EA	$38,895.68	$4,625.36	$1,057,200.00	$0.00	$275,180.26	$1,100,721.00	MIL
Fuel Oil Tankage	2	EA	$9,000.00	$1,500.00	$91,522.00	$0.00	$51,011.00	$102,022.00	USR
Compaction, steel wheel tandem roller, 5 ton	240	CY	$53.50	$46.70	$0.00	$0.00	$0.42	$100.00	AF
Backfill, strl, sand & gravel, no cmpct, 75 HP dozer, 50' haul	2040	CY	$702.78	$354.76	$0.00	$0.00	$0.52	$1,058.00	RSM
Concrete ready mix, regular weight, 3500 psi	100	CY	$0.00	$0.00	$6,425.00	$0.00	$64.25	$6,425.00	RSM
Finishing floors, monolithic, broom finish	2100	SF	$835.80	$0.00	$0.00	$0.00	$0.40	$836.00	MIL
Finishing floors, add, hardener,metallic, .50 PSF, heavy service	2100	SF	$809.97	$0.00	$1,176.00	$0.00	$0.95	$1,986.00	MIL
Fence, CL scty, galv,10'H, 2.5"line post@10',3"pull	300	LF	$2,782.20	$1,228.59	$4,170.00	$0.00	$27.27	$8,181.00	MIL
Total			**$345,684.24**	**$10,883.21**	**$1,423,028.10**	**$0.00**	**$1,779,595.55**	**$1,779,596.00**	
Locality Factor	2.01		$694,825.32	$21,875.25	$2,860,286.48	$0.00	$3,576,987.06	$3,576,987.96	
Contingency	12%		$83,379.04	$2,625.03	$343,234.38	$0.00	$429,238.45	$429,238.56	
SIO	6.50%		$50,583.28	$1,592.52	$208,228.86	$0.00	$260,404.66	$260,404.72	
Grand Total			***$828,787.64***	***$26,092.80***	***$3,411,749.71***	***$0.00***	***$4,266,630.16***	***$4,266,631.24***	

Critical Load Backup Generators

Table 33. Critical load backup generator cost detail.

Description	Quantity	Units	Labor	Equipment	Material	Other	Unit Cost	Total Cost	Source
Primary Facilities									
Building									
CMU, decorative, 8" x 8" x 16", split/scored split, no	6030	SF	$26,109.90	$0.00	$24,421.50	$0.00	$8.38	$50,531.00	MIL
CMU, decorative, 8" x 8" x 16", split/scored split, no	6030	SF	$26,109.90	$0.00	$24,421.50	$0.00	$8.38	$50,531.00	MIL
Framing, joists, 2" x 4"	3316.5	BF	$2,222.06	$0.00	$1,956.74	$0.00	$1.26	$4,179.00	RSM
Framing, joists, 2" x 4"	3316.5	BF	$2,222.06	$0.00	$1,956.74	$0.00	$1.26	$4,179.00	RSM
Sheathing, plywood on roof, ext CDX, 3/4" thick	6030	SF	$2,773.80	$0.00	$4,884.30	$0.00	$1.27	$7,658.00	MIL
Sheathing, plywood on roof, ext CDX, 3/4" thick	6030	SF	$2,773.80	$0.00	$4,884.30	$0.00	$1.27	$7,658.00	MIL
Wall/ceiling insul,3.5" thk,R11, 15" W, fbgls, foil faced,	6030	SF	$1,025.10	$0.00	$1,929.60	$0.00	$0.49	$2,955.00	MIL
Wall/ceiling insul,3.5" thk,R11, 15" W, fbgls, foil faced,	6030	SF	$1,025.10	$0.00	$1,929.60	$0.00	$0.49	$2,955.00	MIL
Wall/ceiling insul, 6" thk, R19, 15" W, fbgls, foil faced,	9,510.00	SF	$1,997.10	$0.00	$3,804.00	$0.00	$0.61	$5,801.00	MIL
Walls & ceilings, plywood pnl & veneer, spray, one coat, appl	9,510.00	SF	$1,141.20	$0.00	$0.00	$0.00	$0.12	$1,141.00	CIV
Ctg & paints, Type I paint, TT-P-615, 600 SF/Gal	9,510.00	SF	$0.00	$0.00	$475.50	$0.00	$0.05	$476.00	CIV
Sheathing, plywood, exterior CDX, 5/8" thick	10,841.40	SF	$5,745.94	$0.00	$7,263.74	$0.00	$1.20	$13,010.00	MIL
Roof truss, 2" x 4",1' overhang,32' span, plate conn,24" OC,4/12	142.65	EA	$3,616.18	$1,121.23	$10,772.93	$0.00	$108.73	$15,510.00	MIL
Asphalt shingles,210-235 lb/sq, inorganic, class A, std strip	10,841.40	SQ	$537,733.44	$0.00	$277,431.43	$0.00	$75.19	$815,165.00	MIL
Excavate trench, hvy soil, 4'-6' D, 3/4 CY excavator	402.00	CY	$478.38	$205.02	$0.00	$0.00	$1.70	$683.00	CIV
Backfill, sand bedding trenches, front-end loader, 1.5 CY	301.50	CY	$301.50	$208.04	$4,778.78	$0.00	$17.54	$5,288.00	MIL
Concrete ready mix, regular weight, 3500 psi	100.50	CY	$0.00	$0.00	$6,457.13	$0.00	$64.25	$6,457.00	RSM
Forms in place, footing, spread, plywood, 1 use	804.00	SF	$2,749.68	$0.00	$1,366.80	$0.00	$5.12	$4,116.00	MIL
CMU, back-up, 12" x 8" x 16", no scaf/reinf, 2000 psi	2,412.00	SF	$9,744.48	$0.00	$4,727.52	$0.00	$6.00	$14,472.00	MIL
Excavating, bulk, dozer, small area, open site, shaping w/small	9,510.00	CY	$7,227.60	$3,613.80	$0.00	$0.00	$1.14	$10,841.00	MIL
Base, prepare & roll sub-base, small areas to 2500 SY	1055.61	SY	$538.36	$401.13	$0.00	$0.00	$0.89	$939.00	MIL
Concrete ready mix, regular weight, 3500 psi	190.20	CY	$0.00	$0.00	$12,220.35	$0.00	$64.25	$12,220.00	RSM
Finishing floors, monolithic, float finish	9510	SF	$3,328.50	$0.00	$0.00	$0.00	$0.35	$3,329.00	MIL
Clear & grub, clear site w/335 HP dozer, trees to 12" dia	99.99	EA	$252.97	$442.96	$0.00	$0.00	$6.96	$696.00	AF
Clear & grub, grub & stack, 400 HP dozer	399.96	CY	$115.99	$251.97	$0.00	$0.00	$0.92	$368.00	AF
Ltg misc	1	LS	$0.00	$0.00	$0.00	$45,000.00	$45,000.00	$45,000.00	USR
power misc.	1.00	LS	$0.00	$0.00	$0.00	$65,000.00	$65,000.00	$65,000.00	USR
Overhead coml, no frame, manual, 10' x 10' H, steel, 24 ga	6.00	EA	$1,852.26	$0.00	$3,076.86	$0.00	$821.52	$4,929.00	MIL
Overhead bridge crane, 2 girder, 25 ton, 50' span	5.00	EA	$20,976.00	$2,920.00	$292,984.85	$0.00	$63,376.17	$316,881.00	MIL

Table 34. Critical load backup generator cost detail.

Description	Quantity	Units	Labor	Equipment	Material	Other	Unit Cost	Total Cost	Source
Generators and Unfrastructure									
Generator set, gas turbine, 6000 kW	5.00	EA	$441,895.80	$52,549.00	$8,000,000.00	$0.00	$1,698,888.96	$8,494,445.00	MIL
Generator set, dsl eng, xfr sw&fuel tank, 250 kW, incl btry,	0.00	EA	$0.00	$0.00	$0.00	$0.00	$49,406.44	$0.00	MIL
Generator set, dsl eng, xfr sw&fuel tank, 300 kW, incl btry,	2.00	EA	$7,025.27	$919.82	$98,500.00	$0.00	$53,222.54	$106,445.00	MIL
Automatic transfer switch, 600 amp, enclosed 600 volt, 4 pole	1.00	EA	$644.52	$0.00	$10,631.25	$0.00	$11,275.77	$11,276.00	MIL
Automatic transfer switch, access, time delay relay	1.00	EA	$77.34	$0.00	$226.40	$0.00	$303.74	$304.00	MIL
Automatic transfer switch, access, under voltage relay	1	EA	$77.34	$0.00	$428.00	$0.00	$505.34	$505.00	MIL
Automatic transfer switch, four position selector switch, access	1	EA	$115.89	$0.00	$387.20	$0.00	$503.09	$503.00	MIL
Automatic transfer switch, access, pilot light	4	EA	$309.37	$0.00	$368.00	$0.00	$169.34	$677.00	MIL
Automatic transfer switch, aux contact when normal fails,access	2	EA	$154.68	$0.00	$212.80	$0.00	$183.74	$367.00	MIL
Automatic transfer switch, access, plant exerciser	1	EA	$154.68	$0.00	$292.00	$0.00	$446.68	$447.00	MIL
Automatic transfer switch, access, battery charger	2	EA	$309.37	$0.00	$1,216.00	$0.00	$762.68	$1,525.00	MIL
Oil filled xfmr,500 kVA xfmr, liquid containment area, curb &	1	EA	$1,631.61	$29.60	$394.09	$0.00	$2,055.30	$2,055.00	MIL
Cu bus duct w/ fitting & support, 800 amp, 3P, 4W, feeder	400	LF	$10,760.64	$0.00	$110,000.00	$0.00	$301.90	$120,761.00	MIL
Substn,112.5-1500kVA xfmr, 15 kV, 600A,2 posn floor mtd, fused	1	EA	$844.30	$126.15	$11,034.50	$0.00	$12,004.95	$12,005.00	MIL
Substn, dry xfmr, 500 kVA, 13800 V pri, 480y/277 V secondary	1	EA	$707.15	$17.36	$13,100.00	$0.00	$13,824.52	$13,825.00	MIL
Substn, switchgear 277/480 V, manual, 800 A, w/air circuit	10	EA	$4,050.17	$688.17	$26,625.00	$0.00	$3,136.33	$31,363.00	MIL
Swyd substa, vacuum CB, 1200 A, 500 MVA, 13.8 kV	8	EA	$6,051.92	$904.27	$76,912.00	$0.00	$10,483.52	$83,868.00	MIL
Shielded ca, in duct, 500 kcmil, no splice/termn, copper, XLP,	5.2	MLF	$7,867.24	$1,175.56	$29,640.00	$0.00	$7,439.00	$38,683.00	MIL
Conduit in conc slab, 1.5" dia, incl cplg, steel, rigid	2200	LF	$6,182.00	$0.00	$6,974.00	$0.00	$5.98	$13,156.00	MIL
Special wires & fittings, #14-2 conductor, sound, shielded with	17.6	MLF	$15,340.86	$0.00	$5,755.20	$0.00	$1,198.64	$21,096.00	MIL
Cable tray ladder type, al, 6" rung spacing, 6" wide	1300	LF	$6,006.00	$0.00	$13,312.00	$0.00	$14.86	$19,318.00	RSM
Swyd substa, vacuum CB, 1200 A, 500 MVA, 13.8 kV	8	EA	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	USR
Sychronizing Switchgear Section	1	EA	$25,000.00	$0.00	$100,000.00	$0.00	$125,000.00	$125,000.00	USR
Fuel Oi Fuel Oil Tankage	12		$54,000.00	$9,000.00	$549,132.00	$0.00	$51,011.00	$612,132.00	USR
Compaction, steel wheel tandem roller, 5 ton	1,440.00	CY	$320.98	$280.22	$0.00	$0.00	$0.42	$601.00	AF
Fence, CL scty, galv,10'H, 2.5"line post@10',3"pull	500	LF	$4,637.00	$2,047.65	$6,950.00	$0.00	$27.27	$13,635.00	MIL
Backfill, strl, sand & gravel, no cmpct, 75 HP dozer, 50' haul	3,750.00	CY	$1,291.88	$652.13	$0.00	$0.00	$0.52	$1,944.00	RSM
Finishing floors, add, hardener,metallic, .50 PSF, heavy service	12600	SF	$4,859.82	$0.00	$7,056.00	$0.00	$0.95	$11,916.00	MIL
Finishing floors, monolithic, broom finish	12600	SF	$5,014.80	$0.00	$0.00	$0.00	$0.40	$5,015.00	MIL
Concrete ready mix, regular weight, 3500 psi	470	CY	$0.00	$0.00	$30,197.50	$0.00	$64.25	$30,198.00	RSM
Support Facilities									
Aluminum cable, ACSR, on poles, 477.0	15.4	MLF	$11,714.78	$1,305.46	$20,555.00	$0.00	$2,180.21	$33,575.00	AF
Steam connection	1	LS	$0.00	$0.00	$0.00	$65,000.00	$65,000.00	$65,000.00	USR
Site prep	1	LS	$0.00	$0.00	$0.00	$225,000.00	$225,000.00	$225,000.00	USR
DCS connection to CHP	1	LS	$0.00	$0.00	$0.00	$335,000.00	$335,000.00	$335,000.00	USR
MCASES Sub-Total			**$1,279,106.71**	**$78,859.54**	**$10,400,341.67**	**$735,000.00**	**$12,493,307.90**	**$12,493,308.00**	
Locality Factor	2.01		$2,571,004.49	$158,507.68	$20,904,686.76	$1,477,350.00	$25,111,548.88	$25,111,549.08	
Contingency	12%		$308,520.54	$19,020.92	$2,508,562.41	$177,282.00	$3,013,385.87	$3,013,385.89	
SIO	6.50%		$187,169.13	$11,539.36	$1,521,861.20	$107,551.08	$1,828,120.76	$1,828,120.77	
Grand Total			***$3,066,694.15***	***$189,067.96***	***$24,935,110.36***	***$1,762,183.08***	***$29,953,055.50***	***$29,953,055.74***	

Operational and Maintenance Costs

The recurring operational and maintenance costs that have been included with the analysis of the conversion to heating only are as follows:

- diesel fuel
- combustion turbine generator maintenance
- diesel engine generator maintenance
- PRV maintenance
- control training, support, and maintenance
- security personnel
- coal costs
- electricity purchases from GVEA.

Diesel Fuel Costs

The cost of diesel fuel has been included since it will be consumed during the monthly testing that will be required to ensure that the generators will reliably start when needed during the event of a power loss from GVEA. The estimate is based on one, 2-hr full load test conducted every 2 weeks. The details of the fuel cost estimate are presented in Table 35.

Generator Routine Maintenance Costs

The cost of routine maintenance has been included since hours of generator operation will be accumulated during the monthly testing. Scheduled testing will be required to ensure that the generators will reliably start when needed during the event of a power loss from GVEA. The estimate is based on one 2-hr full load test conducted every 2 weeks. Table 36 lists the details of the routine maintenance cost estimate.

PRV Maintenance

The cost of routine maintenance has been included for the PRV and desuperheater stations. This new equipment will require annual routine maintenance to ensure proper operation and desired reliability. Table 37 lists the annual maintenance cost estimates.

Table 35. IC engine fuel cost estimate.

Combustion Turbines			
Solar Taurus 70			
Oil consumption rate at full load		610.00	gph
Number of turbine sets		5.00	
Subtotal fuel (gallons/hour)		3,050.00	gph
Hours / test		2.00	hours
Subtotal fuel		6,100.00	gal.
Tests per year		26	
Annual Fuel Requirement		158,600.00	gal.
Estimated Fuel Cost		1.046	$/gal
Annual Fuel Cost for Turbines	$	165,895.60	
Diesel Generator Sets			
1.5 MW Caterpillar			
Oil consumption rate at full load		108.00	gph
Number of turbine sets		4.00	
Subtotal fuel (gallons/hour)		432.00	gph
Hours / test		2.00	hours
Subtotal fuel		864.00	gal.
Tests per year		26.00	
Annual Fuel Requirement		22,464.00	gal.
Estimated Fuel Cost		1.046	$/gal
Annual Fuel Cost for Diesel Generators	$	23,497.34	

Total Annual Fuel Costs	Total Cost ($)	
Annual Fuel Cost for Turbines	$	165,895.60
Annual Fuel Cost for Diesel Generators	$	23,497.34
Total	$	189,392.94

Table 36. IC engine maintenance cost estimate.

PRV maintenance			
Man-Hours per Annual Test		2	hrs/PRV
Rebuild every 5 years		2	men
		2	days
		8	hrs/day
		32	hrs/prv/5yrs
Average Annual Maintenance Time / PRV		8.4	hrs/yr/PRV
Total Number of PRV's		7	
Average Annual Maintenance Time		58.8	Hrs/yr
Labor Rate		95	$/hr
	$	5,586.00	
Annual Equipment Costs		3,500.00	parts
Annual Maintenance Cost	**$**	**9,086.00**	

Table 37. Annual maintenance cost estimates.

PRV maintenance			
Man-Hours per Annual Test		2	hrs/PRV
Rebuild every 5 years		2	men
		2	days
		8	hrs/day
		32	hrs/prv/5yrs
Average Annual Maintenance Time / PRV		8.4	hrs/yr/PRV
Total Number of PRV's		7	
Average Annual Maintenance Time		58.8	Hrs/yr
Labor Rate		95	$/hr
	$	5,586.00	
Annual Equipment Costs		3,500.00	parts
Annual Maintenance Cost	**$**	**9,086.00**	

Controls

Recurring annual costs for the control system consists of system training for CHP operators, software updates, and parts replacements. It is anticipated that the only cost during the initial years will consist of training. Beyond the initial years, periodic training, software upgrades and replacement costs are projected with costs increasing every 5 years. Table 38 lists the projected cost schedule.

Security

To provide for continuous Force Protection, costs have been estimated for routine inspections of the substations and generator facilities to ensure that a breach of security has not occurred. Table 39 lists the basis of the annual cost estimate.

Coal and Electricity Costs

The annual cost of electricity presented in 6.5.8 for GVEA rate schedule GS(2)-2 were used. The coal requirement was calculated based on the projected heating loads. The annual costs are presented in Table 40.

Table 38. Control system projected cost schedule.

2002	$	-	**2015**	$	40,000
2003	$	25,600	**2016**	$	75,000
2004	$	25,600	**2017**	$	75,000
2005	$	25,600	**2018**	$	75,000
2006	$	20,000	**2019**	$	75,000
2007	$	20,000	**2020**	$	75,000
2008	$	20,000	**2021**	$	100,000
2009	$	20,000	**2022**	$	100,000
2010	$	20,000	**2023**	$	100,000
2011	$	40,000	**2024**	$	100,000
2012	$	40,000	**2025**	$	100,000
2013	$	40,000	**2026**	$	125,000
2014	$	40,000	**2027**	$	125,000

Table 39. Security annual cost estimate.

Security Inspection Rounds			
Time required per inspection		0.25	hrs/site/shift
Number of sites to inspect per shift		7	sites
Number of shifts per day		3	shifts/day
Days per year for inspections		365	days/yr
Total Annual Man-Hours Required		1916.25	hrs/yr
Security Cost/Hour		65	$/hr
Total Annual Security Costs	**$**	**124,556.25**	

Table 40. Electric and coal annual project costs.

Year	MWh/year	Electric ($)	Coal ($)	Total ($)
2002	93,198	$6,736,100	$6,842,054	$13,578,154
2003	98,033	$7,055,745	$7,191,186	$14,246,931
2004	120,289	$8,579,524	$7,554,796	$16,134,319
2005	132,608	$9,534,348	$7,841,837	$17,376,185
2006	152,806	$11,058,281	$8,213,236	$19,271,517
2007	171,196	$12,420,041	$8,709,589	$21,129,630
2008	169,840	$12,300,462	$9,107,684	$21,408,146
2009	176,796	$12,776,772	$9,560,351	$22,337,123
2010	183,456	$13,213,880	$10,019,550	$23,233,429
2011	185,291	$13,213,880	$10,119,745	$23,333,625
2012	187,144	$13,213,880	$10,220,943	$23,434,822
2013	189,015	$13,213,880	$10,323,152	$23,537,032
2014	190,905	$13,213,880	$10,426,384	$23,640,263
2015	192,815	$13,213,880	$10,530,648	$23,744,527
2016	194,743	$13,213,880	$10,635,954	$23,849,834
2017	196,690	$13,213,880	$10,742,314	$23,956,193
2018	198,657	$13,213,880	$10,849,737	$24,063,616
2019	200,644	$13,213,880	$10,958,234	$24,172,114
2020	202,650	$13,478,157	$11,067,816	$24,545,974
2021	204,676	$13,478,157	$11,178,495	$24,656,652
2022	206,723	$13,478,157	$11,290,280	$24,768,437
2023	208,790	$13,478,157	$11,403,182	$24,881,339
2024	210,878	$13,478,157	$11,517,214	$24,995,371
2025	212,987	$13,478,157	$11,632,386	$25,110,543
2026	215,117	$13,478,157	$11,748,710	$25,226,867
2027	217,268	$13,478,157	$11,866,197	$25,344,354

9 Lifecycle Cost Analysis

Key Assumptions of the Analysis

- Fort Wainwright's coal-fired central plant will be required for the generation of steam as long as Fort Wainwright remains open.
- The installation has a current minimum power load of 10 MW in the summer and a maximum power load of 17 MW in the winter. The installation has a steam heat load of approximately 265,000 lb/hr during peak demand (at -60 °F)
- The installation has a projected year 2010 minimum power load of 20 MW in the summer and a maximum power load of 32.5 MW in the winter.
- The installation has a projected year 2010 steam heat load of approximately 400,000 lb/hr during peak demand (at –60 °F)
- The heating plant is currently the only method of supplying steam for heating the facilities on the installation due the infrastructure of the utilidors. Fort Wainwright has an extensive steam supply and condensate infrastructure in place that cannot be served from other steam sources, private or public.
- The initial investment required for the conversion to heating only project is $78,000,000.
- The annually recurring maintenance cost for the heating plant, backup generator testing, and backup generator maintenance is $470,000.
- Additional operating costs are the cost of coal for the heating plant and the cost of electricity purchased from GVEA.
- This analysis has been generated using a discount rate of 3.2 percent
- This analysis uses the Inflation Index of 2.1 percent annually.

Life Cycle Cost Summary

Table 41 lists the lifecycle costs for each cost component with the inflation rates applied. This information is the output of the ECONPACK software package provided by the U.S. Army Corps of Engineers. Table 42 lists the resulting annual present value and cumulative net present values for the expenses presented above, which indicate that the NPV for the project is $480 million.

The economic analysis compared two alternative methods of satisfying the requirement. Alternative 1 included the cost of modifications to the CHPP to convert it to heating only operation, plus electrical system upgrades and the provision of backup power for an estimated cost of $78 million as detailed in this report. Alternative 2 includes upgrading and expanding the capacity of the CHPP to meet future electrical and thermal loads of the installation at a cost of $153 million. Major equipment changes consist of the conversion to an air-cooled condenser ($36 million), installation of two new steam turbine generators ($42 million), and an upgrade of the substation ($18.3 million). The cost of all improvements and modifications is estimated to be $153 million, with average annual operating costs estimated to be $340,800 plus the cost of coal. Furthermore, cost uncertainties in terms of the condition of the existing equipment may lead to unforeseen costs in future years.

The Net Present Values generated in the analysis are:

- Convert CHPP to heating only: $480.1 million
- Upgrade and Expand Capacity: $472.1 million.

Table 41. Projected lifecycle costs.

Year	Initial Construction	Generator Fuel	Turbine Generator Maintenance	Diesel Generator Maintenance	PRV Maintenance	Controls Maintenance	Security	Coal	Electricity	Total Annual Outlays
2003	$78,000,000	$0	$0	$0	$0	$0	$0	$7,191,186	$7,055,745	$92,246,931
2004	$0	$192,526	$95,148	$28,545	$9,236	$26,024	$126,617	$7,554,796	$8,579,524	$16,612,416
2005	$0	$195,318	$96,528	$28,958	$9,370	$26,401	$128,452	$7,841,837	$9,534,348	$17,861,213
2006	$0	$198,540	$98,121	$29,436	$9,525	$26,836	$130,572	$8,213,236	$11,058,281	$19,764,548
2007	$0	$201,916	$99,789	$29,937	$9,687	$21,322	$132,792	$8,709,589	$12,420,041	$21,625,072
2008	$0	$205,550	$101,585	$30,475	$9,861	$21,706	$135,182	$9,107,684	$12,300,462	$21,912,506
2009	$0	$209,661	$103,617	$31,085	$10,058	$22,140	$137,885	$9,560,351	$12,776,772	$22,851,569
2010	$0	$214,064	$105,793	$31,738	$10,270	$22,605	$140,781	$10,019,550	$13,213,880	$23,758,680
2011	$0	$218,559	$108,014	$32,404	$10,485	$23,080	$143,737	$10,219,941	$13,213,880	$23,970,101
2012	$0	$223,149	$110,282	$33,085	$10,705	$47,129	$146,756	$10,424,340	$13,213,880	$24,209,327
2013	$0	$227,835	$112,598	$33,780	$10,930	$48,119	$149,838	$10,632,826	$13,213,880	$24,429,806
2014	$0	$232,620	$114,963	$34,489	$11,160	$49,129	$152,984	$10,845,483	$13,213,880	$24,654,708
2015	$0	$237,505	$117,377	$35,213	$11,394	$50,161	$156,197	$11,062,393	$13,213,880	$24,884,120
2016	$0	$242,492	$119,842	$35,953	$11,633	$51,215	$159,477	$11,283,640	$13,213,880	$25,118,132
2017	$0	$247,584	$122,359	$36,708	$11,878	$98,044	$162,826	$11,509,313	$13,213,880	$25,402,592
2018	$0	$252,784	$124,928	$37,479	$12,127	$100,103	$166,245	$11,739,500	$13,213,880	$25,647,046
2019	$0	$258,092	$127,552	$38,266	$12,382	$102,205	$169,737	$11,974,290	$13,213,880	$25,896,403
2020	$0	$263,512	$130,230	$39,069	$12,642	$104,351	$173,301	$12,213,775	$13,478,157	$26,415,038
2021	$0	$269,046	$132,965	$39,890	$12,907	$106,543	$176,940	$12,458,051	$13,478,157	$26,674,499
2022	$0	$274,696	$135,758	$40,727	$13,178	$145,040	$180,656	$12,707,212	$13,478,157	$26,975,424
2023	$0	$280,464	$138,608	$41,583	$13,455	$148,086	$184,450	$12,961,356	$13,478,157	$27,246,159
2024	$0	$286,354	$141,519	$42,456	$13,738	$151,196	$188,323	$13,220,583	$13,478,157	$27,522,326
2025	$0	$292,368	$144,491	$43,347	$14,026	$154,371	$192,278	$13,484,995	$13,478,157	$27,804,033
2026	$0	$298,507	$147,525	$44,258	$14,321	$197,016	$196,316	$13,754,695	$13,478,157	$28,130,795
2027	$0	$304,776	$150,623	$45,187	$14,621	$201,153	$200,439	$14,029,789	$13,478,157	$28,424,746
%NPV	15.99	0.8	0.4	0.12	0.04	0.24	0.53	37.71	44.18	
	$76,781,175	$3,842,741	$1,899,123	$569,737	$184,353	$1,134,392	$2,527,213	$181,062,137	$212,089,870	

Table 42. Present value and cumulative NPV.

YEAR	PRESENT VALUE	CUMULATIVE NET PRESENT VALUE
2003	$90,805,484	$90,805,484
2004	$15,845,766	$106,651,250
2005	$16,508,655	$123,159,906
2006	$17,701,413	$140,861,319
2007	$18,767,176	$159,628,494
2008	$18,426,960	$178,055,455
2009	$18,620,786	$196,676,240
2010	$18,759,643	$215,435,884
2011	$18,339,709	$233,775,593
2012	$17,948,394	$251,723,986
2013	$17,550,245	$269,274,232
2014	$17,162,610	$286,436,842
2015	$16,785,183	$303,222,025
2016	$16,417,666	$319,639,691
2017	$16,088,754	$335,728,445
2018	$15,739,903	$351,468,348
2019	$15,400,132	$366,868,480
2020	$15,221,468	$382,089,948
2021	$14,894,361	$396,984,309
2022	$14,595,339	$411,579,648
2023	$14,284,712	$425,864,360
2024	$13,982,076	$439,846,435
2025	$13,687,200	$453,533,635
2026	$13,418,659	$466,952,294
2027	$13,138,446	$480,090,741

Figure 14 shows the cumulative net present values of the two options, for comparison.

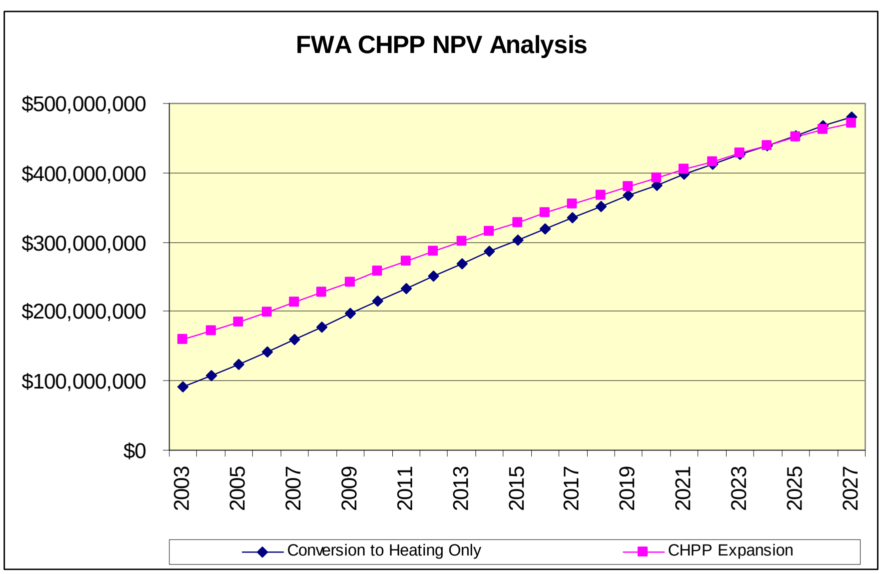

Figure 14. FWA CHPP NPV analysis.

This economic analysis shows that the conversion of the CHPP to heating only is the lower first cost option and that the 25 year NPV is within 2 percent of the alternative. The NPV of the heating only option is lower than the CHPP expansion option for the first 20 years until 2024 when they are nearly equal. Beyond 2024, the plant expansion, as modeled, has the more favorable NPV. The level of uncertainty of annual cost comparisons of the two options in the years beyond the first 15 is considered fairly high as the probability of additional impacts increases. The main driver in the later years is that the annual outlay for electricity and coal is estimated to be greater than the cost of coal only for the generation of both electricity and heat.

A sensitivity analysis indicates that the results could favor either option if additional costs were encountered during implementation, or if annual costs were to increase. The estimate with the highest certainty is the conversion to heating only as this approach relies more on new equipment purchase and a switch to electric supply by the local utility, whereas the expansion option relies on continued reliability of the older existing equipment of the CHPP. Furthermore, the conversion to heating only is favorable for discount rates above 4.3 percent and the plant expansion is favorable for discount rates less than 4.3 percent

10 Environmental Considerations

Introduction

The CHPP conversion to a CHP will result in environmental impacts from changes at the CHPP and from the installation of new substations and backup power generators. The potential impacts include air pollution emissions, groundwater and surface water contamination, noise, and increased exposure to electric and magnetic fields (EMF). From the viewpoint of both cost and environmental effects, air quality impacts are by far the most significant.

FWA produces air pollution emissions from a wide variety of sources including the CHPP, fuel storage and dispensing operations, aerospace activity, landfills, remediation sites, ozone depleting substances, and fugitive dust. The CHPP is by far the largest stationary source of air pollution at FWA. The primary pollutants from the CHPP are nitrogen oxides (NO_x), sulfur oxides (So_x), and carbon monoxide (CO). FWA's Title V Operating Permit Application indicates that estimated potential emissions of particulate matter (PM_{10}) would be reduced from 749.0 tons/year (TPY) to 13.0 TPY after the completion of the ongoing baghouse project.

FWA's Title V Operating Permit application reports that the installation is classified as a Prevention of Significant Deterioration (PSD) Major Facility and a Nonattainment Area (NAA) Major Facility.* The application for an operating permit is now under review by the Alaska Department of Environmental Conservation (ADEC) and should be issued sometime in FY03. Fort Wainwright is located in a Serious CO nonattainment area. Future expansion at Fort Wainwright must in-

* Major stationary sources of air pollution and major modifications to major stationary sources are required by the Clean Air Act to obtain an air pollution permit before commencing construction. The process, called new source review (NSR), is required whether the major source or modification is planned for an area where the national ambient air quality standards (NAAQS) are exceeded (nonattainment areas), or where an area where air quality is acceptable (attainment and unclassifiable areas). Permits for sources in attainment areas are referred to as prevention of significant air quality deterioration (PSD) permits, while permits for sources located in nonattainment areas (NAA) are referred to as NAA permits.

clude careful consideration of how the increased activity will affect the quantity and type of air emissions from the installation.

The CHPP has been in violation of opacity limitations since opacity limitations have been part of the Alaska air pollution regulations. Poor opacity is caused by excessive emissions of particulate matter. PM emissions at the CHPP are only partly controlled by a multicyclone that offers good control efficiency for relatively large particles, but poor efficiency for the small particles that are the most efficient at creating high opacity plumes. Compliance with air quality regulations at the CHPP has been a major issue since 1992 when the ADEC began reporting violations of the opacity requirement. Fort Wainwright was subject to a formal complaint from USEPA because of emissions from the CHPP. The USEPA calculated a fine of $27.02M: $750,000 due to seriousness of violation, $12M due to recapture of economic benefit, and $14M due to size of business. Even though this penalty was reduced to a maximum of $2M in Section 314 of the FY01 DOD Authorization Act, the Army was (and at this writing still is) contesting this penalty. The Army believes the penalties were not calculated properly and did not want this case to set a precedent.

CHPP Boiler Impacts on Emissions of Air Pollutants

The CHPP is currently undergoing projects to modernize the boilers and install baghouses to control PM emissions. ADEC has issued construction permit 0031-AC059 to cover these changes and air pollution emissions from the Bassett Army Community Hospital Replacement project and planned soil restoration work. At the CHPP, the permit covers emissions from coal combustion in the boilers, propane combustion from in-duct heaters, and coal preparation activities. The propane duct burners are being installed to prevent low temperature flue gas from entering the baghouse during boiler startup, shutdown, or malfunctions. Once installed, a properly operating baghouse should easily prevent the CHPP from exceeding opacity and flue gas concentration limits.

The construction permit contains limitations and conditions on the operations and emissions from the CHPP. Table 43 lists these limitations as they appear in Fort Wainwright's Title V application. In most cases, these limitations were agreed upon by Fort Wainwright to prevent the changes from being classified as major under the provisions of the Prevention of Significant Deterioration (PSD) Major Facility or New Source Review (NSR) programs. All these conditions and limitations would remain in effect until the permit is modified or replaced by a new permit.

Table 43. Permit application: enforceable limitations summary.

FORM 4B

Equipment or Group ID#	Enforceable Limitation	Compliance Method Description
EU01 Central Heat and Power Plant	336,000 TPY coal	Facility operating reports to record the amount of coal burned per month and maintain 12-month rolling total of coal consumption.
EU01 Central Heat and Power Plant	Visible emissions may not reduce visibility through the exhaust effluent by greater than 20% for more than 3 minutes in any 1 hour.	Monitor and record opacity for each successive 10-second period using COMS.
EU01 Central Heat and Power Plant	Limit PM_{10} emissions to less than 0.05 gr./dscf	Reference Section 2 of the CAM Plan in Appendix F of this permit application. Comply with the Permit to Construct 0031-AC059 Conditions 28.1 thru 28.3.
EU01 Central Heat and Power Plant	SO_2 emissions may not exceed 500 PPM averaged over 3 hours.	Conduct an analysis of a representative sample using the procedures established in ASTM D3176-74 to determine the weight percent, dry basis of sulfur, carbon, nitrogen, and oxygen. For the same boiler load used in the calculation, determine the volume percent of oxygen in the exhaust with an oxygen analyzer or by an ORSAT analysis, and calculate the 3-hour exhaust concentration of SO_2.
EU01 Central Heat and Power Plant	Atmospheric gas emissions shall not exceed 20% opacity or greater.	Monitor and record opacity for each successive 10-second period using COMS.
EU01 Central Heat and Power Plant	Limit monthly average steam production to 150,000 lbs/hr/b/r.	Calculate and record the average daily steam production rate based on hours of operation per day and steam production readings recorded at no less than 10-minute intervals.
EU01 Central Heat and Power Plant	Burn a grade of propane with a fuel sulfur content not to exceed 250 PPM by weight	Obtain a certification from supplier. If certification is unavailable, analyze a sample of fuel from each shipment to determine sulfur content using an approved ASTM method.

FORM 4B

Equipment or Group ID#	Enforceable Limitation	Compliance Method Description
EU01 Central Heat and Power Plant	Limit the total NO_X emissions to two tons [(1)] per 12-month rolling period.	Monitor and record the cumulative total monthly NO_X emissions. Calculate and record the cumulative 12-month rolling total NO_X emissions using the run time for each burner system. Alternatively, NO_X emissions can be calculated by monitoring fuel burner propane consumption, and calculating the emission rates using the published AP-42 emission factor 19lbs NO_X /1000 gallons of propane burned. Based on this heating value of propane, 90,500 Btu/gal., this factor is equivalent to 0.210 lbs NO_X /MMBtu. Report in the Facility Operating Report required by the Permit to Construct 0031-AC059 Condition 41, the cumulative monthly and 12-month rolling total NO_X emissions.
EU01 Central Heat and Power Plant	Do not use coal containing greater than 30% by weight fines content.	Analyze a sample from each coal shipment to determine fine content using an approved ASTM method.

The conversion of the CHPP to a CHP would initially result in significantly less coal being burned. Emissions would be proportionately reduced. For example, if the conversion of the CHPP occurred in FY03, it is anticipated that the coal usage rate at the CHP would drop from 204,523 TPY to 134,800 TPY. However, because of the large expansion projects planned for Fort Wainwright, the coal consumption required to meet the annual heating load would grow back to 200,000 TPY by 2010. Table 44 shows both the estimated emission reductions in 2003 and the follow on emission increases in 2010 that would occur with these changes in coal usage. Figure15 shows these same changes graphically for NO_x, CO, and SO_2. All emission rates were estimated using the same procedures used in the Title V application. The PM and PM_{10} emission rates shown in Table 44 are estimates of the emissions after the baghouse is installed at the CHPP. The emission decreases that would occur after the conversion to a CHP cannot be credited as a net emission decrease since the decreases will be essentially eliminated by 2010 and the decreases would not be permanent or enforceable.

Table 44. Estimated actual emission changes of criteria air pollutants at the CHPP (tons/year).

Pollutant	Year		
	2002	2003	2010
NO_X	726.06	478.54	710.00
CO	511.31	337.00	500.00
SO_2	608.46	401.03	595.00
PM	—	8.09	12.00
PM_{10}	—	4.85	7.20
VOC	5.11	3.37	5.00

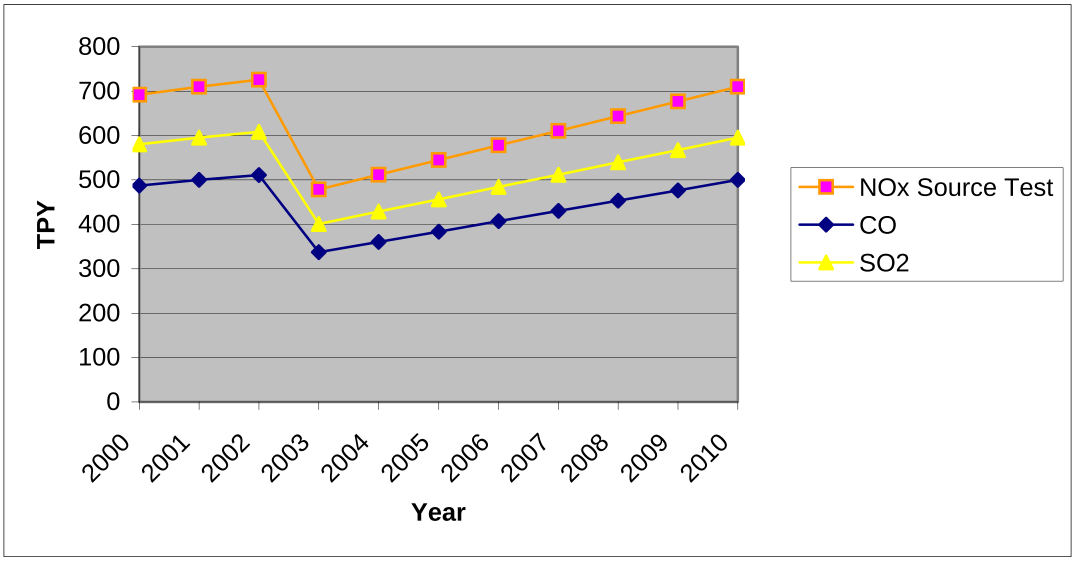

Figure 15. Actual emissions changes at the coal fired boilers.

The possible exception to this would be if FWA were willing to accept a lower limitation on coal usage. This limitation is probably not a good idea since it would effectively reduce the capacity of the CHP to produce heat up to its full capabilities. Table 45 shows estimates of emission changes for many other pollutants. All emission factors used to make these emission estimates were taken from FWA's Title V application.

Although the emissions at the CHP would grow significantly in response to the increased heat load, these increases would not be counted towards the NO_X threshold levels (significance levels) that would trigger PSD permit review or NSR. This is because the emission increases are related to changes in process throughput and not to a physical or permanent process change. Changes in throughput do not trigger PSD permit review or NSR.

Table 45. Estimated actual emission changes at the CHPP (lb/year).

Pollutant	Year		
	2002	2003	2010
Arsenic	83.85443	55.268	82
Beryllium	4.294983	2.8308	4.2
Formaldehyde	7.36E-10	4.85E-10	7.2E-10
Hydrochloric Acid Mist	245427.6	161760	240000
Hydrofluoric Acid Mist	30678.45	20220	30000
Antimony	3.681414	2.4264	3.6
Cadmium	10.43067	6.8748	10.2
Chromium	53.17598	35.048	52
Chromium (VI)	16.15732	10.6492	15.8
Cobalt	20.4523	13.48	20
Magnesium	2249.753	1482.8	2200
Manganese	100.2163	66.052	98
Mercury	16.97541	11.1884	16.6
Nickel	57.26644	37.744	56
Selenium	265.8799	175.24	260
Biphenyl	0.347689	0.22916	0.34
Acenaphhene	0.104307	0.068748	0.102
Acenapthylene	0.051131	0.0337	0.05
Anthracene	0.04295	0.028308	0.042
Benzo(a)anthracene	0.016362	0.010784	0.016
Benzo(a)pyrene	0.007772	0.005122	0.0076
Benzo(b,j,k)fluoranthene	0.022498	0.014828	0.022
Benzo(g,h,I)perylene	0.005522	0.00364	0.0054
Chrysene	0.020452	0.01348	0.02
Fluoranthene	0.145211	0.095708	0.142
Fluorine	0.186116	0.122668	0.182
Indeno(1,2,3-cd)pyrene	0.012476	0.008223	0.0122
Napthalene	2.658799	1.7524	2.6
Phenanthrene	0.552212	0.36396	0.54
Pyrene	0.067493	0.044484	0.066
5-Methyl chrysene	0.0045	0.002966	0.0044
2,3,7,8-TCDD	2.92E-06	1.93E-06	2.86E-06
Total TCDD	1.9E-05	1.25E-05	1.86E-05
Total PeCDD	9.14E-06	6.03E-06	8.94E-06
Total HxCDD	5.87E-06	3.87E-06	5.74E-06
Total HpCDD	1.71E-05	1.12E-05	1.67E-05
Total OCDD	8.51E-05	5.61E-05	8.32E-05
Total PCDD	0.000136	8.98E-05	0.000133
2,3,7,8-TCDF	1.04E-05	6.87E-06	1.02E-05
Total TCDF	8.26E-05	5.45E-05	8.08E-05
Total PeCDF	7.22E-05	4.76E-05	7.06E-05
Total HxCDF	3.93E-05	2.59E-05	3.84E-05

Pollutant	Year		
	2002	2003	2010
Total HpCDF	1.57E-05	1.04E-05	1.54E-05
Total OCDF	1.36E-05	8.94E-06	1.33E-05
Total PCDF	0.000223	0.000147	0.000218
Acetaldehyde	116.5781	76.836	114
Acetophenone	3.067845	2.022	3
Acrolein	59.31167	39.092	58
Benzene	265.8799	175.24	260
Benzyl chloride	143.1661	94.36	140
Bis(2-ethylhexyl)phthalate	14.93018	9.8404	14.6
Bromoform	7.976397	5.2572	7.8
Carbon disulfide	26.58799	17.524	26
2-Chloroacetophenone	1.431661	0.9436	1.4
Chlorobenzene	4.499506	2.9656	4.4
Chloroform	12.06686	7.9532	11.8
Cumene	1.083972	0.71444	1.06
Cyanide	511.3075	337	500
2,4-Dinitrotoluene	0.057266	0.037744	0.056
Dimethyl sulfate	9.817104	6.4704	9.6
Ethyl benzene	19.22516	12.6712	18.8
Ethyl chloride	8.589966	5.6616	8.4
Ethylene dichloride	8.18092	5.392	8
Ethylene dibromide	0.245428	0.16176	0.24
Formaldehyde	49.08552	32.352	48
Hexane	13.70304	9.0316	13.4
Isophorone	118.6233	78.184	116
Methyl bromide	32.72368	21.568	32
Methyl chloride	108.3972	71.444	106
Methyl ethyl ketone	79.76397	52.572	78
Methyl hydrazine	34.76891	22.916	34
Methyl methacrylate	4.09046	2.696	4
Methyl tert butyl ether	7.158305	4.718	7
Methylene chloride	59.31167	39.092	58
Phenol	3.272368	2.1568	3.2
Propionaldehyde	77.71874	51.224	76
Tetrachloroethylene	8.794489	5.7964	8.6
Toluene	49.08552	32.352	48
1,1,1-Trichloroethane	4.09046	2.696	4
Styrene	5.113075	3.37	5
Xylenes	7.567351	4.9876	7.4
Vinyl acetate	1.554375	1.02448	1.52
Total Trace Metals	2793.989	1841.503	2732.2
Total Polynuclear Aromatic Hydrocarbons (PAH)	4.245488	2.798178	4.1516

Pollutant	Year		
	2002	2003	2010
Total PCDD/PCDF	0.00036	0.000237	0.000352
Total Various	1878.826	1238.324	1837.276
Organic Cmpds (TVOC)			
(PAH+PCDD/PCDF+TVOC)	1883.072	1241.122	1841.428
Total Trace HAPs			

The CHP can continue to increase boiler output until it violates one of the enforceable limitations shown in Table 43. It is unlikely that any of these limitations would be violated since they allow the CHP to operate at near full capacity. However, if a significant physical or permanent process change were made at the CHPP, then the commensurate emission changes would need to be considered in an NSR applicability analysis at FWA.

Potential Environmental Impacts of New Substations

Stormwater Runoff Management During Construction and Operation

This should be minor to negligible, and should be mitigable.

Possible Adverse Health Impacts on Nearby Residents During the Operational Phase of the Project

Potential human health impacts due to exposure to electric and magnetic fields (EMF) during operation of the proposed substations are addressed. An authoritative report under the auspices of the National Institute of Environmental Health Sciences noted that evidence from epidemiological studies suggests "small increased risk with increasing exposure" associated with two forms of cancer, childhood leukemia and chronic lymphocytic leukemia in occupationally exposed adults. However, the results of laboratory (animal and human) toxicology and mechanistic studies predominantly fail to indicate a cause-and-effect relationship between exposure to EMF at environmental levels and disease. Magnetic field levels in the vicinity of the proposed substation were calculated for current and future peak summer loading conditions, using a computer model that has been tested and verified by power engineers. The highest magnetic fields occur inside the substation yard fence and under the transmission lines, and the magnetic field levels decay with increasing distance from the transmission lines and the transformers. Future magnetic fields along the Installation perimeter fences adjoining the substation will be highest near the northwest corner of the substation. These calculated results indicate magnetic fields ranging from background low levels (comparable to the lowest values measured under indoor home conditions) to maximum values similar to magnetic fields found within a few inches of common household appliances.

Noise Impacts

Noise impacts from operation of the proposed substations need to be addressed. This would require data from GVEA on noise levels around their standard substation. Possible language:

> Future noise levels were estimated for the initial installation (one transformer) and maximum loading (four transformers), based on measured current ambient sound levels at the site. The results indicate that low-noise transformers must be used. DPW will install fence slatting along the northern substation yard fence, and slatting will be provided along the northern Installation perimeter fence to attenuate noise levels for homes adjoining the northern Installation perimeter fence. In addition, AP proposes tree planting in the limited available space between the fences. The combined effects of these measures will reduce the noise levels for the potentially affected homes and will be in compliance with the regulations governing noise in residential areas. DPW will conduct noise level surveys of the substation following the installation of each of the transformers to ensure regulatory compliance.

Cumulative Environmental Impacts

Increased stormwater runoff is a potential cumulative impact that must be mitigated. No other identifiable cumulative environmental impacts from the proposed action are apparent.

Operation of the substation at full capacity will increase noise and magnetic field levels in the vicinity. Fence slatting and planting of trees will mitigate noise levels below State of Alaska regulatory limits. Also, DPW will conduct noise level surveys of the initial substation and later increases in capacity to ensure regulatory compliance. Although magnetic field levels will increase with operation of the substation, they will remain within the range of typical indoor home environments. A cause-and-effect relationship between such EMF levels and adverse human health impacts has not been demonstrated.

Conclusions

The principal conclusions are: (1) Implementation of the proposed actions would result in no significant, nonmitigable, adverse environmental or socioeconomic impacts related to the construction phase of the project. There is no compelling evidence that operation of the substations will cause adverse impacts to human health. (2) Siting the substation at another location would either be incompatible with the availability of suitable land elsewhere on installation, based on current land use planning, or outside the Installation and near the existing substation and transmission lines.

Potential Environmental Impacts of Backup Power Generators

Air Quality Impacts

The conversion to a CHP requires the installation of large diesel-fired electrical generators to provide full backup in the case of electrical interruption from GVEA. Although these generators would be operated infrequently, their large size would result in significant emissions after a short period of operation. Table 46 lists the generators used in the recommended backup options. This generator mix is designed to completely cover the maximum peak electrical demand of 32.5 MW anticipated for 2010.

Table 46. Backup generator required for conversion to CHP.

Type and size	Number of Sets	Total Generation
6.5 MW Combustion turbine	5	32.5 MW
0.15 MW Reciprocating engine	2	0.30 MW
1.5 MW Reciprocating engine	4	6 MW

A combination of EPA and vendor provided emission factor information was used to estimate potential emissions from these generators. Since the largest emissions from these generators are NO_X and CO, vendor guaranteed emission factors were obtained for these pollutants. Most manufacturers of backup electrical power systems can provide equipment that generates much smaller emissions of NO_X than would be predicted using EPA emission factors. FWA could take advantage of this by adding required emission levels to the electrical generator equipment specifications and then adding these same emissions levels to a construction permit as a user requested limitation to avoid triggering PSD permit review. These emission levels would likely need to be verified through periodic emissions stack tests. Tables 47 and 48 list both EPA and vendor provided emission factors for criteria air pollutants for combustion turbine generators and diesel engine generators, respectively. Note the decrease from the EPA NO_X emission factor to the vendor provided NO_X emission factor.

Table 47. Criteria air pollutant emission factors for combustion turbine generators (lb/MMBtu) fuel input.

Pollutant	Emission Factor
NO_X	8.80E-01
NO_X from vendor	3.70E-01
CO	3.30E-03
CO from vendor	1.18E-01
SO_2	3.03E-01
VOC	4.10E-04
PM	1.20E-02
Pb	1.40E-05

Table 48. Criteria air pollutant emission factors for reciprocating engine generators (lb/hp-hr) power output.

Pollutant	Emission Factor
NO_X	2.40E-02
NO_X from vendor	1.50E-02
CO	5.50E-03
CO from vendor	1.50E-03
SO_2	2.43E-03
PM	7.00E-04
VOC	7.10E-04

To not trigger EPA PSD reviews, the generators can only be operated in a manner that generates no more than an estimated 20.32 TPY of NO_X. This number represents the difference between the 40 TPY NO_X increase threshold that triggers PSD permit review and the estimated 19.68 TPY increase in NO_X stemming from new facilities at FWA (e.g., deployment of the Stryker Brigade Combat Team (SBCT) at FWA). Table 49 shows the changes in emissions relative to the change thresholds that trigger PSD reviews for all criteria pollutants.

The amount of NO_X emitted will depend on the amount of time the generators are operated and the mixture of reciprocating engine and combustion turbine generators. An analysis was performed to estimate emissions from both generator types, combine them, and add in the effects of the other planned combustion sources at FWA. Table 50 shows criteria air pollutant emission estimates for the five 6.5 MW combustion turbine generators at different operating intervals. Table 51 shows the same emission estimates for the reciprocating engine generators. Assuming that both types of generators are operated for the same amount of time for maintenance and backup power production, then the emissions can be added to estimate total emissions from both generator types.

Table 49. Cumulative net emission change for PSD evaluation at Fort Wainwright main post.

Activity	Pollutant Emissions (tons/year)				
	NO_X	SO_X	CO	VOC	PM_{10}
Emissions Baseline	2,848	1,310	2,388	163	768
CHPP Upgrade/Baghouse Project	0	0	0	0	-546.2
Install Boilers and Generators at new hospital	9.63	2.91	2.23	0.31	0.35
Remove Boilers and Generators at Bassett	-0.17	-0.02	-0.04	-0.01	-0.01
SBCT EIS Projects	8.32	0.55	1.79	0.67	0.62
SBCT Vehicle Fielding, Deployment, Training, Maneuver Activities	1.9	0	0.7	0.3	19.4
Net Emissions Change	19.68	3.44	4.68	1.27	-525.84
PSD/NSR Thresholds	40	40	100	40	15

Table 50. Emission calculations for five 6.5 MW turbine generators (tons/year).

Pollutant	Operating time (hours/year)				
	120	200	350	500	8760
NO_X	19.9	33.2	58.1	82.9	1,453.1
NO_X from vendor	8.4	13.9	24.4	34.9	611.0
CO	0.1	0.1	0.2	0.3	5.4
CO from vendor	2.7	4.4	7.8	11.1	194.8
SO_2	6.9	11.4	20.0	28.6	500.3
VOC	0.0	0.0	0.0	0.0	0.7
PM	0.3	0.5	0.8	1.1	19.8

Table 51. Emission calculations for four 1.5 MW and two 0.15 MW reciprocating engine generators (tons/year).

Pollutant	Operating time (hours/year)				
	120	200	350	500	8,760
NO_X	12.2	20.3	35.5	50.7	887.7
NO_X from vendor	7.6	12.7	22.2	31.7	554.8
CO	2.8	4.6	8.1	11.6	203.4
CO from vendor	0.8	1.3	2.2	3.2	55.5
SO_2	1.2	2.0	3.6	5.1	89.8
PM	0.4	0.6	1.0	1.5	25.9
VOC	0.4	0.6	1.0	1.5	26.3

The generator emissions can then be added to emissions shown in Table 49 to account for all emissions contributing towards the NO_X threshold. Figure 16 shows how NO_X and other criteria air pollutants will vary with the operating time of the backup generators when the emissions from Table 49 are included.

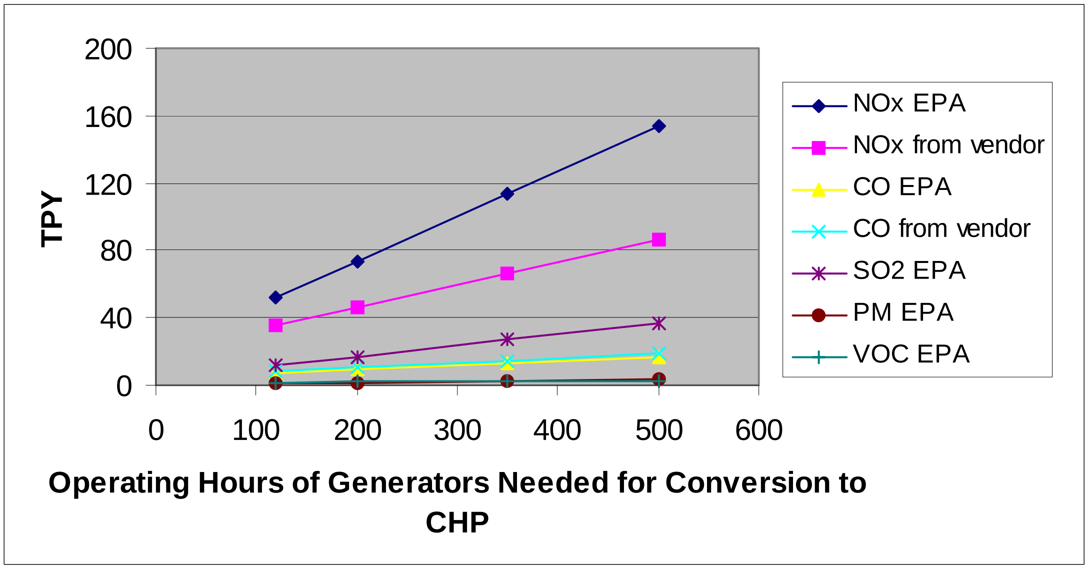

Figure 16. Emissions from new combustion sources at FWA contributing towards the PSD threshold for NO_X.

If EPA emission estimation methods are used, the generators could run 75 hrs before the NO_x threshold is exceeded. If vendor guaranteed emission estimates are used, then the generators could operate 151 hrs before exceeding the threshold. The hours of operation include the generator operation time required for maintenance purposes which could be as much as 2 hrs a month. If the generators are run 2 hrs a month for maintenance, that leaves 51 or 127 hrs of operation allowed for generating emergency power. To avoid a PSD permit review, FWA must either accept this level of limitation on the hours of operation of the generators in a permit, add NO_x emission control technology to the generators, or create a creditable NO_x emission reduction at another combustion source. The EPA has published emission factors for noncriteria air pollutants for both combustion turbines and diesel powered reciprocating engines. Table 52 lists these emission factors and corresponding emission estimates for the five 6.5 MW combustion turbine generators and Table 53 contains emission estimates for the four 1.5 MW reciprocating engine generators.

Since the generators are powered by diesel fuel, emissions of volatile organic compounds (VOCs) will occur. The emissions occur during tank filling and from breathing losses due to temperature changes. These emissions can be estimated using the EPA's TANKS storage tank emissions calculation software. TANKS allows users to enter specific information about a storage tank (dimensions, construction, paint condition, etc.), the liquid contents (chemical components and liquid temperature), and the location of the tank (nearest city, ambient temperature, etc.), and generate an air emissions report.

Table 52. Non-criteria emission estimates for five 6.5 MW combustion turbine generators (lbs/year).

Pollutant	Emission Factor (lbs/MMBTU)	Operating hours/year				
		120	200	350	500	8760
TOC	4.00E-03	180.96	301.6	527.8	754	13210.08
1,3-Butadiene	1.60E-05	0.72384	1.2064	2.1112	3.016	52.84032
Benzene	5.50E-05	2.4882	4.147	7.25725	10.3675	181.6386
Formaldehyde	2.80E-04	12.6672	21.112	36.946	52.78	924.7056
Naphthalene	3.50E-05	1.5834	2.639	4.61825	6.5975	115.5882
PAH	4.00E-05	1.8096	3.016	5.278	7.54	132.1008
Arsenic	1.10E-05	0.49764	0.8294	1.45145	2.0735	36.32772
Beryllium	3.10E-07	0.0140244	0.023374	0.040905	0.058435	1.023781
Cadmium	4.80E-06	0.217152	0.36192	0.63336	0.9048	15.8521
Chromium	1.10E-05	0.49764	0.8294	1.45145	2.0735	36.32772
Lead	1.40E-05	0.63336	1.0556	1.8473	2.639	46.23528
Manganese	7.90E-04	35.7396	59.566	104.2405	148.915	2608.991
Mercury	1.20E-06	0.054288	0.09048	0.15834	0.2262	3.963024
Nickel	4.60E-06	0.208104	0.34684	0.60697	0.8671	15.19159
Selenium	2.50E-05	1.131	1.885	3.29875	4.7125	82.563

Table 53. Non-criteria emission estimates for four 1.5MW and two 0.15 MW reciprocating engine generators (lbs/year).

Pollutant	Emission Factor (lbs/MMBTU)	Operating Hours/Year				
		120	200	350	500	8760
Benzene	7.76E-04	4.98825216	8.3137536	14.54907	20.78438	364.1424
Toluene	2.81E-04	1.80631296	3.0105216	5.268413	7.526304	131.8608
Xylenes	1.93E-04	1.24063488	2.0677248	3.618518	5.169312	90.56635
Propylene	2.79E-03	17.9345664	29.890944	52.30915	74.72736	1309.223
Formaldehyde	7.89E-05	0.50718182	0.845303	1.47928	2.113258	37.02427
Acetaldehyde	2.52E-05	0.16198963	0.2699827	0.47247	0.674957	11.82524
Total HAPs	Sum of above	26.6389379	44.39823	77.6969	110.9956	1944.642
Acrolein	7.88E-06	0.0506539	0.0844232	0.147741	0.211058	3.697735
Naphthalene	1.30E-04	0.8356608	1.392768	2.437344	3.48192	61.00324
Acenaphthylene	9.23E-06	0.05933192	0.0988865	0.173051	0.247216	4.33123
Acenaphthene	4.68E-06	0.03008379	0.0501396	0.087744	0.125349	2.196117
Fluorene	1.28E-05	0.08228045	0.1371341	0.239985	0.342835	6.006473
Phenanthrene	4.08E-05	0.26226893	0.4371149	0.764951	1.092787	19.14563
Anthracene	1.23E-06	0.00790664	0.0131777	0.023061	0.032944	0.577184
Fluoranthene	4.03E-06	0.02590548	0.0431758	0.075558	0.10794	1.8911
Pyrene	3.71E-06	0.02384847	0.0397475	0.069558	0.099369	1.740939
Benz(a)anthracene	6.22E-07	0.00399832	0.0066639	0.011662	0.01666	0.291877
Chrysene	1.53E-06	0.00983508	0.0163918	0.028686	0.04098	0.717961
Benzo(b)fluoranthene	1.11E-06	0.00713526	0.0118921	0.020811	0.02973	0.520874

Pollutant	Emission Factor (lbs/MMBTU)	Operating Hours/Year				
		120	200	350	500	8760
Benzo(k)fluoranthene	2.18E-07	0.00140134	0.0023356	0.004087	0.005839	0.102298
Benzo(a)pyrene	2.57E-07	0.00165204	0.0027534	0.004818	0.006883	0.120599
Indeno(1,2,3-cd)pyrene	4.14E-07	0.00266126	0.0044354	0.007762	0.011089	0.194272
Dibenz(a,h)anthracene	3.46E-07	0.00222414	0.0037069	0.006487	0.009267	0.162362
Benzo(g,h,l)perylene	5.56E-07	0.00357406	0.0059568	0.010424	0.014892	0.260906
TOTAL PAH	2.12E-04	1.36276992	2.2712832	3.974746	5.678208	99.4822

Figures 17 and 18 show screen captures of the tanks' physical characteristics and emission report outputs for the combustion turbine generators' fuel tank and the reciprocating engine generators' fuel tank. Both tanks were assumed to be above-ground and that the entire tank contents would be replaced every year. The throughput assumptions are very conservative since, during most years, the generators would only be operated for maintenance purposes and the fuel tanks are sized to provide a full week of fuel. The TANKS program did not include fuel properties for arctic diesel fuel so jet kerosene was selected instead. This again is a conservative assumption since jet kerosene is more volatile than arctic diesel.

The fuel for the combustion turbines would be supplied by a single tank as specified in Figure 17 while the fuel for the reciprocating engines will be supplied by two of the fuel tanks specified in Figure 18. So the total annual VOC emissions would be:

28.27 lbs + 2 * 7.76 lbs = 44 lbs/yr

These emissions are much smaller than the combustion emissions from the operation of the generators and therefore their impacts are of much less concern.

Since the new generators could be a source that causes FWA to exceed the NO_x threshold, FWA may need to evaluate emission control technologies for the backup power generation equipment (e.g., diesel engine and combustion turbine generators) to proactively avoid PSD permitting. The most likely control technology for NO_x would be selective catalytic reduction (SCR). SCR controls NO_x emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O.

TANKS 4.0
Emissions Report - Summary Format
Tank Identification and Physical Characteristics

Identification

User Identification:	Combustion Turbine Tank
City:	Fairbanks
State:	Alaska
Company:	
Type of Tank:	Vertical Fixed Roof Tank
Description:	Tank for DF1 to power combustion turbine generators

Tank Dimensions

Shell Height (ft):	32.00
Diameter (ft):	50.00
Liquid Height (ft):	32.00
Avg. Liquid Height (ft):	28.00
Volume (gallons):	450,000.00
Turnovers:	1.00
Net Throughput (gal/yr):	450,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition:	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft):	1.60
Slope (ft/ft) (Cone Roof):	0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Fairbanks, Alaska (Avg Atmospheric Pressure = 14.41 psia)

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Jet kerosene	6.58	21.69	28.27

Figure 17. Tank assumptions and emissions from fuel tank for combustion turbines.

The exhaust gas must contain a minimum amount of O_2 and be within a particular temperature range (typically 450 to 850 °F) for the SCR system to operate properly. SCR has been applied to both diesel-powered reciprocating engines and combustion turbines. Note—these applications are normally not for backup power generation, but for a more continuous use of these combustion sources. The emission control analysis would need to include costs to purchase the equipment, supply an ammonia source, replace the catalyst as it is consumed, monitor the process as specified in a compliance assurance monitoring plan (CAMPLAN), and provide maintenance.

TANKS 4.0
Emissions Report - Summary Format
Tank Identification and Physical Characteristics

Identification

User Identification:	Diesel Engine Generator Tank
City:	Fairbanks
State:	Alaska
Company:	USARAK
Type of Tank:	Horizontal Tank
Description:	Diesel Engine Generator Tank

Tank Dimensions

Shell Length (ft):	48.08
Diameter (ft):	12.25
Volume (gallons):	22,500.00
Turnovers:	1.00
Net Throughput (gal/yr):	22,500.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition:	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Fairbanks, Alaska (Avg Atmospheric Pressure = 14.41 psia)

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Jet kerosene	0.32	7.44	7.76

Figure 18. Tank assumptions and emissions from fuel tank for reciprocating engine generators.

The application of SCR to generators that are operated on such a limited basis would not be as cost effective on a $/(mass of NO_X removed) basis as the application of SCR to sources that are operated more frequently. The amount of catalyst required and the dimensions of the reaction chamber are sized by the flow rate from the combustion process. This is to allow the correct amount of reaction time and contact between the flue gas and the catalyst. Therefore, even though these sources would be operated infrequently, they would require the same amount of catalyst and the same size of reaction chamber as a source with the same flow rate operated on a continuous basis. Some cost savings would occur from infrequent operation for catalyst replacement and purchase of NH_3 containing reagent. However, if NO_X control is ever required at FWA it may be more cost effective to apply the control technology at a more continuously operated source.

Noise Impacts

Noise impacts from operation of the proposed generators needs to be addressed. Need data from vendors or existing facilities at FWA.

Stormwater Runoff Management During Construction and Operation

This should be minor to negligible and mitigable.

Odors

The exhaust gases produces during operation and fuel filling and storage will produce minor short duration odors.

Flood Hazards and Encroachment on Wetlands

The facility site is located in a flood plain, but is protected by the Chena River Lakes flood control project, activated in March 1984. These facilities are subject to flooding under certain conditions. However, the mission dictates that these are located as proposed. The facilities will be designed and sited to minimize adverse effects on flood heights and damages to the structure or contents resulting from floods.

Protection of Historic Properties

This project will not include any new structures that will encroach upon the Ladd Air Force Base Historic District (or Ladd Field National Historic District centered on runways). Therefore, no historic Properties at Fort Wainwright are affected.

This project has been evaluated for impact on historic and archeological property and complies with the National Historic Preservation Act (PL 89-665), as amended, and EO 11593. Figure 19 shows the location of the Ladd Field National Historic District by a dashed green line that surrounds the Ladd Field air field and some buildings in the southwest corner.

Summary/Conclusion

The CHPP conversion to a CHP will result in environmental impacts from changes at the CHPP and from the installation of new substations and backup power generators. The largest environmental impacts from this project will be related to air pollution emission from the CHP and new backup power generators. After the CHPP is converted to a CHP, air pollution emissions will initially drop, but will recover to near pre-CHP levels by 2010 — due to the large expected increase in heating load at FWA as new missions such as the Stryker Brigade come online at FWA.

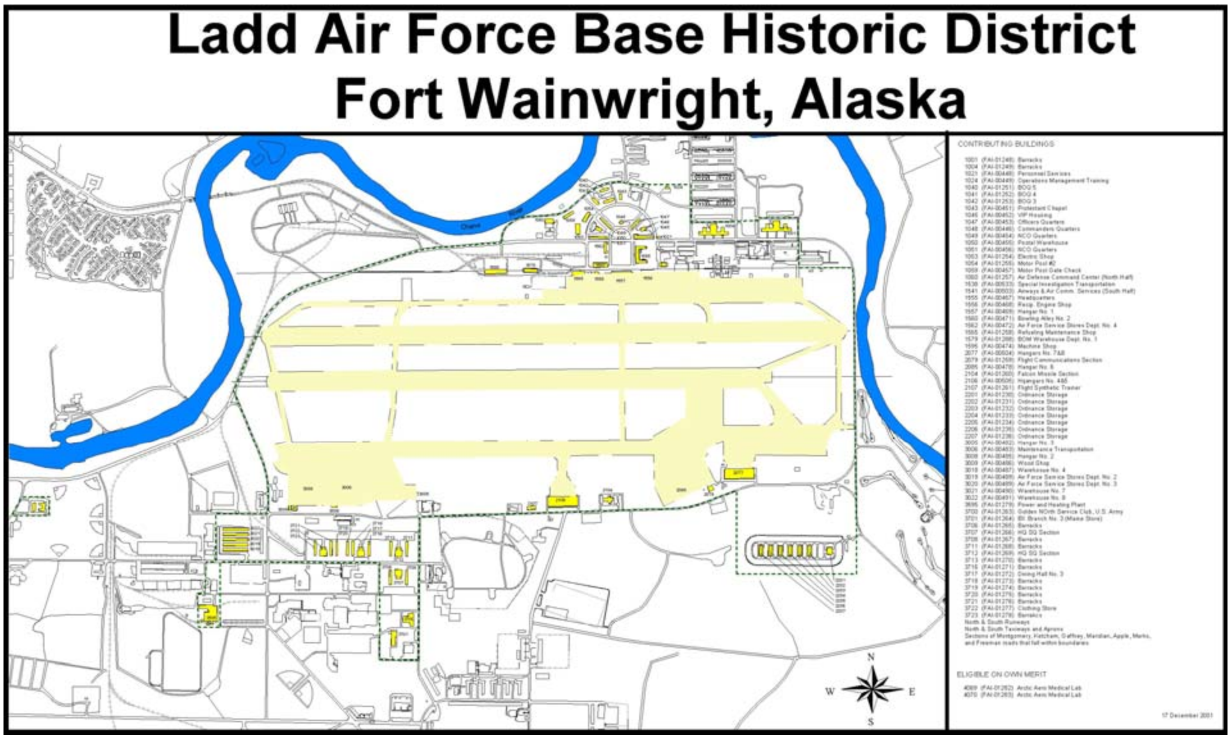

Figure 19. LADD AFB, Fort Wainwright, AK.

However, the emission levels at the CHPP will be much larger in 2010 without the conversion to a CHP since the plant must still burn coal to produce electricity. An estimate of the emissions in 2010 can be calculated by adding the drop in emissions from 2002 to 2003 to the values shown in 2010 (cf. Table 44). Tables 52 and 53 show new emissions from the backup electrical generators for various operating hours. Since the proposed electrical backup capability is so large, these generators will produce large emissions even with a modest number of operating hours. Figures 17 and 18 show estimated VOC emissions from the large fuel tanks required for the generators. These emissions are quite small when compared with the combustion emissions.

The environmental costs for converting the CHPP to a CHP will include permit preparation, new recordkeeping, emission fees, and possibly new emission control technology. Without a PSD permit review, permitting activity could include:

- preparation of a construction permit for the new generators
- modification of the Title V operating permit
- modification of FWA's CAM plan
- preparation of an Environmental Assessment (EA) for the conversion project
- performance of a conformity analysis
- modification of FWA's emergency response plan
- modification of FWA's spill prevention plan
- modification of FWA's storm water pollution prevention plan.

In addition, mitigation costs might be incurred while converting the plant to a CHP for asbestos, lead-based paint, and equipment containing PCBs. The exact cost of this extra work is difficult to estimate and some of it would be performed by FWA staff. However, the costs will certainly be several hundreds of thousands of dollars.

If PSD permit review were triggered, the costs would be significantly higher. With the exception of the conformity analysis, all the costs listed above would again be incurred. PSD review requirements would include the following items:

- atmospheric monitoring
- dispersion modeling studies (local pollutant concentrations and regional haze)
- Best Available Control Technology (BACT) analysis
- permit preparation.

FWA has already undertaken an atmospheric monitoring project that should meet the requirements for PSD. The other aspects of the PSD preparation would cost on the order of $300,000. However, the conditions of the PSD permit are likely to add more cost than the permit preparation. A BACT determination by ADEC could result in the requirement to add air pollution control. The most likely NO_x control technology would be SCR. Purchase and installation of SCR would add several millions of dollars to the purchase price of the generators and significant recurring costs would be incurred for catalyst replacement, makeup reagent, SCR system maintenance, and recordkeeping. ADEC could also require the installation of continuous emission monitors (CEM) for NO_x, which would add cost for purchase, certification, maintenance, and recordkeeping.

<u>From the viewpoint of costs incurred due to environmental regulations, continued operation of the plant in its current configuration is the lowest cost option. This is because changes in emissions from increased throughput in a process do not count towards NSR levels of significance</u>. However, if a future physical or operational change is made at the CHPP that can be linked to an emission increase then a PSD permit review for NO_x is likely. All the requirements discussed in the paragraph above would then apply to the CHPP. <u>Since the threshold for NO_x is relatively small at FWA, a careful PSD applicability analysis must be performed for any new potential source of NO_x at FWA.</u>

11 Anti-Terrorism/Force Protection

Meetings were held with installation physical security personnel and as a result, the following measures were incorporated into the CHP project.

Location of New Infrastructure

The new substations and structures housing the backup generators are to be located so that the remaining tree lines and existing facilities will impair the line of sight to the new construction to obscure from snipers outside the installation perimeter.

New Electrical Substations

The substations will be surrounded with a fence of a height equal to the height of the highest portion of the substation transformers and not less than a height of 6 ft. The fence will consist of a woven wire fencing material that includes a fill material that will provide a visual obstruction into the substation from the outside of the fencing. The fence will have general-purpose barbed tape/concertina wire installed at the top of the fence and at both inside and outside of the bottom of the fence. The fence will include ¾-in. aircraft cable placed around the perimeter at a height of 30 and 36 in. anchored to deadmen located at each corner of the fence. The fence will be located such that it is a minimum of 10 m from any equipment located within the fence. On the exterior of the fence, there will not be any structures or substantial vegetation within 10 m. There will be an improved road outside the fence to allow for a security patrol.

Access to the substation though the fence will be provided through a rolling gate that contains a swing arm cable (Delta Scientific TT212 or equal).

The interior of the substation will be illuminated to a lighting level greater than or equal to 1.0 foot-candle/sq ft. The exterior of the substation to a distance of 10 meters will be illuminated to level greater than or equal to 1.0 foot-candle/sq ft. All lighting will be controlled through a photocell and also have a 60 minute timer switch for manual operation located inside the fenced area.

CCTV cameras will be installed inside the fenced area and placed in such a manner as to cover the entire clear zone inside the fence. Exterior sensors will be provided to cover the areas seen by the CCTVs. The location on the installation that will monitor the CCTVs and the sensors will be determined at a later time. Specifications for the sensors will be provided at a later time.

The road to the substations will be designed so that a sharp right or left turn will be required immediately prior to the gate entrance. This is intended to inhibit the ability for a vehicle to gain significant speed for crashing through the gate.

Backup Generator Housing

The building(s) that will contain the backup generators will be designed and constructed in accordance with the building conventions of the installation. The new building(s) will *not* have any windows. Personnel access doors will be a hollow metal type consisting of a metal rated at a minimum of 16 gage. The doors will have deadbolt with a throw of no less than 1.0 in. and an IDS sensor. Vehicle/equipment access doors will be a metal type consisting of a metal rated at a minimum of 16 gage.

The generator building(s) will be surrounded with a fence of a height equal to the height of the building walls and not less than a height of 6 ft. The fence will consist of a woven wire fencing material. The fence will have general-purpose barbed tape/concertina wire installed at the top of the fence and at both inside and outside of the bottom of the fence. The fence will include ¾-in. aircraft cable placed around the perimeter at a height of 30 and 36-in. anchored to deadmen located at each corner of the fence. The fence will be located such that it is a minimum of 10 meters from any equipment located within the fence. On the exterior of the fence, there will not be any structures or substantial vegetation within 10 meters. There will be an improved road outside the fence to allow for a security patrol.

CCTV cameras will be installed inside the fenced area and placed in such a manner as to cover the entire clear zone inside the fence. Exterior sensors will be provided to cover the areas seen by the CCTVs. The location on the installation that will monitor the CCTVs and the sensors will be determined at a later time. Specifications for the sensors will be provided at a later time.

The road to the generator buildings will be designed so that a sharp right or left turn will be required immediately prior to the gate entrance. This is meant to inhibit vehicles from gaining speed sufficient to crash through the gate.

12 Summary and Recommendations

This project assessed the condition of the Fort Wainwright Central Heat and Power Plant, analyzed alternatives to the current system, and recommended that the installation: (1) convert the CHPP to heating only, (2) purchase all electricity from the local electric utility, GVEA, and (3) install backup generation on the Installation. The following sections outline specific system requirements that must be addressed to adopt the "heating-only" option, and the recommended option (from options detailed in this report) that best meet that requirement.

Control System

Requirement

Reconfigure or replace system so that it controls the CHP (eliminate control points and functions associated with operation of the steam turbine generators).

Option Selected

Option 3 was selected because it provides needed improvements at a reasonable cost. The open architecture of the system facilitates future upgrades without locking-in specific vendors/products. This will also enable easy down loading of archived and performance data to CD-ROM, which is not possible with the current system. The work will consist of the upgrade of the existing system to an Emerson-Westinghouse Ovation system. This requires replacement of distributed processing units and existing WESNET cabling with Ethernet cabling. The distributed control cabinets and control sensors will be retained. The estimated downtime for the conversion is 3 days. The total estimated cost is \$3.9 M.

Steam System Modifications

Requirement

Reduce steam pressure from 400 psig-650 °F to 100 psig-470 F for the Utilidor load, 50 psig for CHP miscellaneous heating, and 10 psig for deaerator heating.

Option Selected

Option 2—(N+1) design strategy—was selected to increase reliability for this critical function. The work will consist of 4 PRVs and desuperheaters for the 100 psig steam, 2 PRVs and desuperheaters for the 50 psig steam, and 2 PRVs and desuperheaters for the 10 psig steam. These are to be located in the boiler building at the platform below the mudroom. If existing isolation valves do not hold, a shutdown of CHP for 1 day may be required. Estimated Cost: $15.5M.

Mothball Steam Turbines

Requirement

Since the steam turbines will no longer be required, the options are to abandon them or to preserve them so that they may be used again at a future time.

Option Selected

Option 1—to abandon the turbines in place—was selected due to the age and relative inefficiency of low-pressure turbine operation dictates any future upgrades consider higher pressures and new technologies. Existing turbines have no commercial value. The estimated cost is $0.2M

Electrical Switchgear

Requirement

Upgrade or replace switchgear to serve the CHP.

Option Selected

Option 2—to convert to a 4,160 volt service—was selected since it improves the reliability by eliminating single points of failure. The estimated cost is $1.6M.

Electrical Substations

Requirement

Upgrade capacity to meet projected 32.5 MW load, include SCADA monitoring capability to bring up to current standards.

Option Selected

Option 2—to incorporate an N+1 design strategy through three substations—was selected since it is a lower cost option and will provide a higher level of reliability and better accommodate the anticipated electrical loads due to new facilities. The estimated cost is $22.0 M.

Heat Plant Backup and Electrical Generation

Requirement

Meet the projected 4.2 MW power requirement for CHP startup and operation in the event of power loss and provide 7 days of fuel storage capacity.

Option Selected

Option 2—to install four dedicated 1,500 kW diesel engine generators—was selected to include the N+1 design strategy for this critical facility. Fuel storage will consist of two tanks with a combined storage capacity of 55,000 gal of diesel fuel. The total estimated cost is $4.3 M.

Installation Critical Electrical Loads

Requirement

Meet the projected critical loads of the installation (not including the CHP).

Option Selected

Option 1—to provide backup of the total installation less the CHP electrical loads—was selected because it the lower cost option, simplest to implement, simplest to operate and most reliable option. This project will meet the total requirements of the installation – 28.3 MW by installing six 6.5 MW diesel fueled combustion turbines (N+1 units), and 2 small diesel engine generators, for combustion turbine start-up. Estimated Cost - $30.0 M

Appendix A: Project Implementation Tasks

Listed below are the tasks required for the conversion of the FWA CHPP to heating only. It was developed as a planning guide and could eventually be converted into a schedule and/or project diagram.

Initiate heating only study to assess requirements for redundancy and reliability for heat and power. The study would include the following:

1. Determine installation-wide heat and power potential failure points
2. Determine various possible backup power options to meet existing and future power loads, to include:
   a. 100 percent Backup Power
   b. Critical building and mission support loads, centralized location
   c. Critical building and mission support loads, decentralized location
3. Determine potential power failure points for each backup power option (Requires a load flow, fault current and protective device coordination study of the installation's entire distribution system)
4. Determine amount of time needed to remain self-sufficient if backup power is needed as a primary power source
5. Develop capital cost estimates and life-cycle costs for each backup power option
6. Determine requirements and provide options to bring all power (reliably) into installation, with some redundancy
7. Develop capital cost estimates and life-cycle costs for each power option
8. Assess power supply impact on local community
9. Assess requirements and costs for CHPP reconfiguration to heating only, to include:
   a. Control system
   b. Steam system modifications
   c. Steam turbines
   d. Switchgear
   e. Staffing levels
10. Assess air pollution emission impacts from CHPP and backup generators
11. Investigate future permitting requirements and potential for new air pollution control technology
12. Seek Congressional language to provide authorization for one new MCA project with the following headings: (1) Back-up power generation (2) Electrical substations and (3) CHPP conversion to heating only.

13. Select backup power option in #12 above
14. Select size and locations of substations in #12 above
15. Select plant conversion options in #12 above
16. Initiate design of new projects
17. Begin negotiations with Alaska DEC regarding applicability and requirements under the New Source Review program
18. Depending on the outcome of #17 above, develop and submit required permit applications and analyses to Alaska DEC
19. Complete design of new projects
20. Submit request for modifying FWA's Title V operating permit to Alaska DEC
21. Execute construction projects
22. Develop emergency power response plan
23. Commission new back-up power system
24. Decommission any unnecessary boiler systems
25. Decommission all steam turbine generators
26. Purchase all electrical power from local utility.
27. Either through an MCA project or through a capital investment by the local utility, complete sub-station upgrade to accommodate the higher electrical loads
28. Determine who will operate and maintain new substations
29. Begin negotiation with local utilities for purchase of power at 138 kV transmission rate
30. Modify FWA RPMA Utilities (J) account to account for increase to energy charges for purchase of all power
31. Negotiate for contract changes to allow purchase up to 32 MW
32. Other environmental and safety issues.
33. Investigate cooling pond closure:
    a. Wetland Issues
    b. Draining
    c. Clean-up
    d. Filling
34. Determine heating only asbestos abatement needs
35. Initiate a study of the long-term (25 yrs) heating and power requirements. The study would include:
    a. Private sector heating for new housing
    b. Standalone heating for new facilities
    c. Private sector options, third party plant on/near installation
    d. Partnering with DOE for new plant technology (research into using an already proven technology)

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14. ABSTRACT

The Fort Wainwright (FWA) military community has a critical need to establish its power and heating requirements to successfully complete a series of planned capital improvements. The CHPP upgrade coincides with an expansion of FWA's mission within the next 5 years. To help the installation successfully complete these changes within the specified time frame, the Construction Engineering Research Laboratory (CERL) conducted an independent technical assessment of the FWA CHPP. This follow-on study, which was completed in April 2003, expanded on the recommendation of the previous work to convert the installation CHPP to heating only, and to purchase all electricity from the local electric utility.

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